Techno-Economic Carbon Management at Danish Biogas Plants

- The Business Case of Utilising the Biogenic Carbon -

Master's Thesis

by

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AALBORG UNIVERSITET
STUDENTERRAPPORT

4th semester
Department of Sustainablility and Planning
Sustainable Energy Planning and Management
Rendsburggade 14, 9000 Aalborg

Title:

Techno-Economic Carbon Management at Danish Biogas Plants

Framework Theme:

Master's Thesis

Project period:

February 2024 - June 2024

Student:

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Supervisor:

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Number of pages: 68
Appendix: 7
Finished: 07-06-2024

Abstract:

Fulfilment of the climate goals in the Danish climate law partly relies on Power-to-X and Carbon Capture and Storage. Biogas upgrading poses an extremely cost-effective way of acquiring biogenic CO_2 that can be utilised by these technologies. Therefore, this thesis examines the business case for biogas plants to utilise the biogenic CO_2.
Three scenarios are simulated using an Excel model that has been developed as part of this thesis. The CO_2 can be (1) sold as liquid CO_2, (2) utilised for production of e-methane, or (3) utilised for production of e-methanol. In all three scenarios, 20,000 ton CO_2 is available annually and all must be utilised. The analysis shows that the liquefaction scenario has a Net Present Value (NPV) of 6.9 million € and a Real Rate of Return (RRoR) of 74%. The e-methane scenario and the e-methanol scenario have NPVs of respectively 29 million € and 17.1 million €, and RRoRs of respectively 9% and 8%.
The liquefaction scenario is evidently the safest investment due to the low costs and the high RRoR. However, the e-methane scenario and the e-methanol scenario have prospects of benefiting from technological development and a more fluctuating future electricity price. In this way, the thesis have examined the preliminary techno-economic feasibility of utilising the CO_2 from biogas plants, and thus it forms a basis for further research.

Preface

I want to thank my supervisor, Anders N. Andersen, for his constructive feedback and suggestions. Throughout the project period, we have had supervisor meetings every other week, where I received comments on my work, and we discussed the upcoming work. I also want to thank Anders Søgaard Kristensen from Rambøll Management Consulting, who has been a partner for discussion and participated in an interview. Kristensen's expertise regarding the market conditions for liquid CO_2, e-methane, and e-methanol has been particularly useful. The interview with Kristensen is attached as Appendix B. Finally, I want to thank Frank Rosager from Biogas Danmark, who participated in an interview. Rosager shared his extensive knowledge on biogas plants and the market conditions for biomethane and e-methane, including biogas certificates and subsidies. The interview with Rosager is attached as Appendix A.

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By signing this document the student confirms to be liable for the content of the project.

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Summary 1

As global warming is becoming an increasingly pressing issue, the fulfilment of climate goals receives more attention. According to the political agreement behind the Danish climate law, Power-to-X and Carbon Capture and Storage (CCS) are expected to contribute to fulfilling the Danish climate goals. Therefore, due to the high costs of Power-to-X and CCS, subsidy schemes are put in place to support the development of the technologies and value chains.

By means of Power-to-X and CCS, biogenic carbon can be utilised to respectively produce renewable fuels and chemicals, and generate negative emissions. When biogas is upgraded to biomethane, the CO_2 in the biogas is separated from the methane and emitted to the atmosphere. Biogas upgrading thus poses an extremely cost effective way of acquiring biogenic carbon. As demand for biogenic carbon increases, biogenic carbon has gone from being a waste product to a valuable commodity. To uncover the business case for biogas plants to utilise the biogenic carbon, this thesis answers the following research question:

From a business economic perspective, what is the feasibility of utilising biogenic carbon emitted from Danish biogas plants?

The research question is answered by examining three scenarios in an Excel simulation model that has been developed for this purpose. The biogenic CO_2 can be (1) sold as liquid CO_2, (2) utilised for on-site production of e-methane, or (3) utilised for on-site production of e-methanol. The market for liquid CO_2 is expected to grow tremendously due to emerging markets of especially renewable fuels and construction materials. The selling price in this analysis is determined to be 65 €/ton CO_2. E-methane can be injected into the gas grid along with the biomethane and sold at the spot price. Besides the spot price, income can be generated from selling biogas certificates that document the sustainability of the methane. The combined value of the spot price (30 €/MWh) and the biogas certificates (250 €/MWh) is determined to be 280 €/MWh e-methane. Despite an increasing demand for e-methanol, the selling price is expected to decrease as a result of decreasing production costs. The selling price is determined to be 1,300 €/ton e-methanol.

The Excel model simulates operation in the three scenarios against the electricity market on an hourly basis. Operation is economically optimised so that all of the available CO_2 (20,000 ton CO_2 annually) is utilised most cost-effectively. Intermediate storages enable operation to take place during the hours with the lowest electricity prices. This entails that a low plant capacity requires many full load hours, and few full load hours require a high plant capacity. The number of full load hours and the plant capacity in each scenario are determined by the kip price. The kip price that provides the optimal balance between full

load hours and plant capacity is found by What-If Analysis in Excel. Table 1.1 shows the results of simulating the three scenarios against the projected electricity price distribution of 2030.

	Liquefaction	**E-methane**	**E-methanol**
Investment Cost	4.5 million €	67.5 million €	42.1 million €
Annual Expenses	394,000 €	20.9 million €	14.1 million €
Annual Production	20,000 ton	100,700 MWh	14,300 ton
Kip Price	125.47 €/MWh	124.50 €/MWh	118.60 €/MWh
Full Load Hours	8,308	8,396	8,097
Electrolysis Capacity	-	26.11 MW	19.24 MW
Plant Capacity	2.41 ton/hour	29.65 MW	9.75 MW
Annual Electricity Consumption	2,700 MWh	222,000 MWh	165,500 MWh
Average Electricity Price	78.89 €/MWh	76.00 €/MWh	75.29 €/MWh
Levelized Cost of Production	37.19 €/ton	256.89 €/MWh	1,203.71 €/ton
Selling Price	65 €/ton	280 €/MWh	1,300 €/ton
Net Present Value	6.9 million €	29 million €	17.1 million €
Real Rate of Return	74%	9%	8%

Table 1.1. Simulation results in the three scenarios

It is found that the liquefaction scenario has the lowest costs and is thus associated with the lowest risk. Additionally, the Real Rate of Return (RRoR) is highest in the liquefaction scenario. The liquefaction scenario shows robustness against changes in the electricity price, as the electricity cost only make up 28% of the total costs. Similarly, the number of full load hours remains the same, when the electricity price distribution changes.

The e-methane scenario and the e-methanol scenario have higher net present values, but they also have much higher costs. Therefore, the RRoR is lower in both scenarios compared to the liquefaction scenario. The electricity cost in the e-methane scenario and the e-methanol scenario make up respectively 64% and 71% of the total costs. This makes the scenarios very sensitive to changes in the electricity price. Contrary to the liquefaction scenario, the number of full load hours varies, when the electricity price distribution changes. When simulating the e-methane scenario and the e-methanol scenario with the electricity price distributions of 2040, 2030, 2023, and 2021, the average capacity factors are respectively 91% and 82%.

From the simulation results the liquefaction scenario appears to be the safest investment due to the low risk and the high RRoR. There are, however, indicators that suggest that the e-methane scenario and the e-methanol scenario may become more profitable than first presumed. The technological development during the next five years will undoubtedly benefit the e-methane scenario and the e-methanol scenario, while it will have very little impact on the liquefaction scenario. It is reasonable to believe that the future electricity price will be much more fluctuating than the 2030 electricity price distribution. The volatility will benefit the flexible operation in the e-methane scenario and the e-methanol scenario. Finally, additional scenarios, such as a private wire to an energy park and centralised e-methanol production, are obvious candidates for further research.

Problem Analysis 2

The purpose of the problem analysis is to outline the problem that this thesis is addressing. In this chapter, the issue of global warming is described, and Denmark's contribution to global warming is accounted for. Denmark's energy and climate policy is likewise described, which includes subsidy schemes to support the development of Power-to-X and Carbon Capture and Storage (CCS). Finally, the potential use of the biogenic CO_2 from the Danish biogas plants is analysed.

2.1 Global Warming

Earth's climate has always been changing between warmer and colder periods. However, these natural climate changes have happened gradually as opposed to the ongoing rapid increase in global temperature caused by human activity. During the last millions of years, the global temperature has not before increased at this rate. 2011-2020 was the warmest decade ever recorded, and every decade the global temperature increases by 0.2 °C. [European Commission, 2024]

The global temperature is increasing owing to emissions of greenhouse gasses to the atmosphere, which creates a global greenhouse effect. The most critical greenhouse gas is CO_2, as other greenhouse gasses, such as methane and N_2O, are emitted in smaller quantities. In 2020, the atmospheric CO_2-concentration had increased by 48% compared to the level before the industrialisation. [European Commission, 2024]

In 2019, the global temperature had increased by 1.1 °C compared to the pre-industrial level, and it is established that a temperature increase of 2 °C will entail disastrous consequences for nature as well as human welfare. As temperature increases, sea levels are rising, the occurrence and severity of natural disasters increases, and biodiversity decreases. Therefore, the international community aims at limiting the global temperature increase to 1.5 °C. [European Commission, 2024]

2.1.1 Denmark's Greenhouse Gas Emissions

Denmark's annual greenhouse gas (GHG) emission per capita peaked in 1996 with 17.3 ton CO_2-equivalents. Since then, it has been reduced to 7.6 ton CO_2-equivalents in 2022. Despite the reduction, Denmark's GHG-emission per capita was still 1.3% higher than the EU average and 11.8% higher than the global average in 2022. The Danish GHG-emissions mainly come from transport, agriculture, and electricity and heat. In 2022, 64% of the Danish GHG-emissions consisted of fossil CO_2, while methane and N_2O made up

21% and 12% respectively. Most of the methane emissions and N_2O-emissions come from agriculture. [Ritchie og Roser, 2024]

Denmark's annual fossil CO_2-emission also peaked in 1996 with 74.90 million tons, but has been reduced to 29.06 million tons in 2022. Most of the fossil CO_2-emission come from combustion of fossil fuels for energy purposes (94%). In this instance, oil (67%) is the biggest contributor followed by coal (14%) and gas (12%). Besides combustion of fossil fuels, fossil CO_2 is emitted from cement production (4%), other industrial processes (2%), and flaring (0.4%). [Ritchie og Roser, 2024]

2.2 Denmark's Energy and Climate Policy

In the 1970s following the oil crises, the Danish energy policy was introduced with the objective of improving security of supply and ensuring affordable and stable energy prices. Later as a response to global warming, the climate aspect was added to the policy area to reduce the GHG-emission. As accounted for in Section 2.1, the most critical greenhouse gas is CO_2, and almost all of Denmark's CO_2-emission is a result of energy production using fossil fuels. This makes energy and climate considerations interdependent. [DEA, 2024c]

In June 2020, the Danish climate law was adopted. The climate law legally binds the Danish government to act on reducing the GHG-emission by 70% in 2030 compared to the level in 1990 and achieving climate neutrality at latest in 2050. The political agreement behind the climate law specifically highlights that developing technologies such as Power-to-X and CCS are necessary for fulfilling the climate goals. Power-to-X and CCS are crucial to transition the hard-to-abate sectors, where other decarbonisation solutions, such as direct electrification, are not viable. Power-to-X fuels can substitute fossil fuels used in heavy and long-haul transport, shipping, aviation, and various industrial processes. CCS can reduce fossil emissions or generate negative emissions, when biogenic carbon is stored. According to the Intergovernmental Panel on Climate Change (IPCC), CCS is a necessity for fulfilling the Paris Agreement. [KEFM, 2020]

2.2.1 Power-to-X

In 2021, the Danish strategy for Power-to-X was published. As a follow-up on the strategy, a political agreement was made in March 2022 to develop and further hydrogen and other sustainable fuels. [DEA, 2024g]

The agreement establishes that Denmark should have 4-6 GW electrolysis capacity in 2030. This expansion should wherever possible happen on market conditions, and it is recognised that it will require additional capacity of wind turbines and photovoltaics to supply the electrolysers with renewable electricity. To support the electrolysis expansion, 170 million € was allocated to a subsidy scheme. The subsidy scheme is based on competitive bidding, where the lowest bids are rewarded with a subsidy until the budget is spent. The subsidy is granted per MWh of produced hydrogen and distributed over 10 years. [KEFM, 2022]

The Danish Energy Agency (DEA) put the subsidy out to tender in April 2023 with a maximum bidding limit of 57.92 €/MWh. Within the bidding limit offers were received totalling around 536 million € over 10 years and a total electrolysis capacity of 675 MW. This indicates a huge interest in and demand for Power-to-X subsidies. Table 2.1 shows the five projects that were granted a subsidy. As it appears from the table, the funds of the subsidy scheme were increased to 177 million €. [DEA, 2024h]

	Company	**Capacity**	**Subsidy**	**Total Subsidy**
Vindtestcenter Måde K/S	European Energy	9 MW	19.31 €/MWh	5,898,912 €
Padborg	European Energy	150 MW	22.20 €/MWh	122,121,430 €
BioCat Roslev	Electrochaea	10 MW	28.96 €/MWh	9,557,297 €
Kassø PtX Expansion ApS	European Energy	10 MW	32.34 €/MWh	10,978,533 €
HyproDenmark	Everfuel	30 MW	32.58 €/MWh	28,431,408 €

Table 2.1. The winners of the Power-to-X tender
[DEA, 2024h]

2.2.2 Carbon Capture and Storage

The latest political agreement concerning CCS is the agreement from September 2023 on strengthened framework conditions for CCS in Denmark. The agreement describes that Denmark has very suitable underground conditions for CCS, and it is estimated that the potential is 12-22 billion tons CO_2. This potential also opens up the prospect of importing CO_2 to Denmark for storage. CCS in Denmark is aimed at waste incineration plants, combined heat and power plants, industrial plants and biogas plants. [KEFM, 2023]

The intent is that CCS in the long term should be economically feasible on its own due to the increasing cost of CO_2 allowances. Until then, subsidy schemes are supporting the development of value chains. In August 2023, the DEA published the tender documents for the NECCS-fund, which is an abbreviation for Negative Emissions via Carbon Capture and Storage. By competitive bidding, the NECCS-fund grants a subsidy per ton of biogenic CO_2 that is permanently stored underground. Disbursement of the subsidies will begin in 2026 up to and including 2032. Table 2.2 shows the winners of the tender, which were announced in April 2024. All three companies will store the CO_2 in Denmark. [Via Ritzau, 2024]

	Subsidy	**Stored CO2**	**Total Subsidy**
BioCirc CO2 ApS	129.85 €/ton	130,700 ton/year	16,972,036 €/year
Bioman ApS	149.83 €/ton	25,000 ton/year	3,745,815 €/year
Carbon Capture Scotland Limited	348.60 €/ton	4,650 ton/year	1,621,008 €/year

Table 2.2. The winners of the NECCS tender
[Via Ritzau, 2024]

In total, the three companies will store 160,350 tons CO_2 annually, however the expectation was that the NECCS-fund would enable storage of 500,000 tons CO_2 annually. The DEA also did not receive any other bids than those of the three winning companies. According to the market operators, the deadline for commissioning in 2026 was too short and there was too much uncertainty regarding the licenses for onshore CCS. [KEFM, 2024]

2.3 Biogenic CO2 from Biogas Plants

It is evident from Section 2.2 that Denmark among other things relies on Power-to-X and CCS to fulfill the climate goals. Both Power-to-X and CCS require carbon capture, which can be accomplished from point sources or with direct air capture. The CO_2 concentration in flue gas is much higher than in the atmosphere, and therefore carbon capture from point sources is less energy intensive and thus more cost-effective than direct air capture. It is, however, still costly to separate CO_2 from flue gas.

Biogas consists of 60-70% methane and 30-40% CO_2. When biogas is upgraded to grid quality, the CO_2 is separated from the methane and emitted to the atmosphere. Carbon capture from biogas plants is thus a very cost-effective approach to acquire biogenic carbon, as the CO_2 is already separated and ready for use. It is estimated that the Danish biogas plants will altogether emit 1.1 million tons CO_2 in 2025 when upgrading biogas to methane. In 2030, the CO_2-emission will increase to 1.4 million tons due to increased production. However, the CO_2-emission will decrease to 1.3 million tons in 2040, as the oldest biogas plants no longer will be subsidised, which will negatively impact production. [DEA, 2023a]

Figure 2.1 shows an estimation of the current CO_2-emission from each individual biogas plant in Denmark with an upgrading plant. The estimation is based on the assumptions that the biogas contains 40% CO_2 prior to upgrading, and that the upgrading plants have capacity factors of 80%. There is 52 biogas plants, and the total CO_2-emission is 834,000 tons CO_2 annually. [Biogas Danmark, 2022]

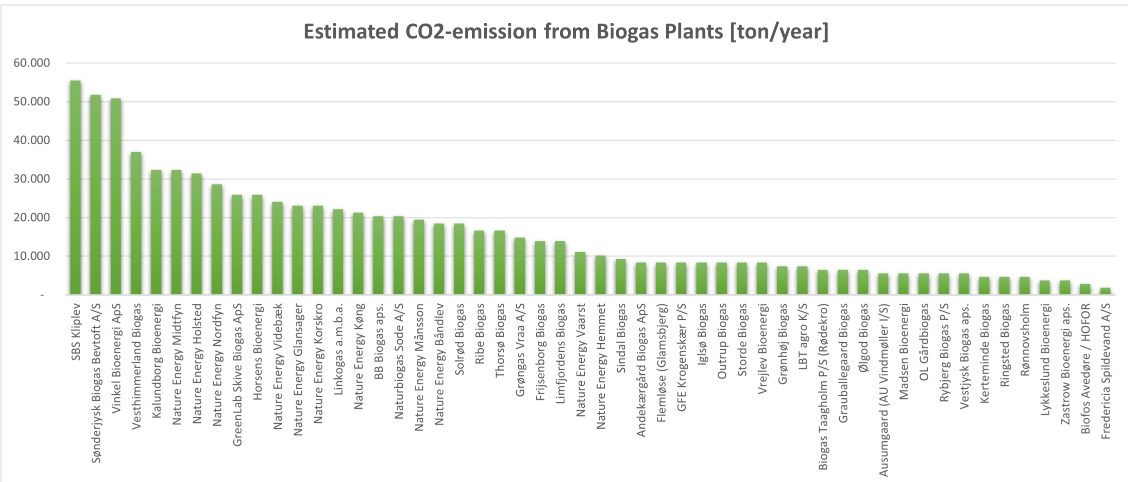

Figure 2.1. The estimated CO_2-emissions from the Danish biogas plants with upgrading plants [Biogas Danmark, 2022]

As CO_2 emitted from biogas plants is biogenic, it holds the potential to be either utilised by means of Power-to-X to produce e-fuels or permanently stored underground to generate negative emissions. With the recent development, CO_2 from biogas plants has thus gone from being a waste product to a valuable commodity. Nevertheless, the basis for a decision is in many cases incomplete, and much uncertainty remains associated with the business case for the biogas plants. To make use of the biogenic CO_2, the business case therefore has to be studied.

Research Design 3

It is evident from Chapter 2 that Power-to-X and Carbon Capture and Storage (CCS) are necessary to fulfil Denmark's climate goals. Both Power-to-X and CCS require biogenic or fossil carbon, and an extremely cost-effective way of acquiring biogenic carbon is from biogas plants. However, as carbon from biogas plants has only recently become a tradeable commodity, the business case is still relatively unexplored. This makes it relevant to answer the following research question:

From a business economic perspective, what is the feasibility of utilising biogenic carbon emitted from Danish biogas plants?

To answer the research question, the research design, which is visualised on Figure 3.1, have been prepared. The green frame illustrates the theoretical framework. The blue box is the research question, which is automatically answered, when the four sub-questions in the red boxes are answered. The sub-questions are answered using the subjacent methods in the yellow boxes.

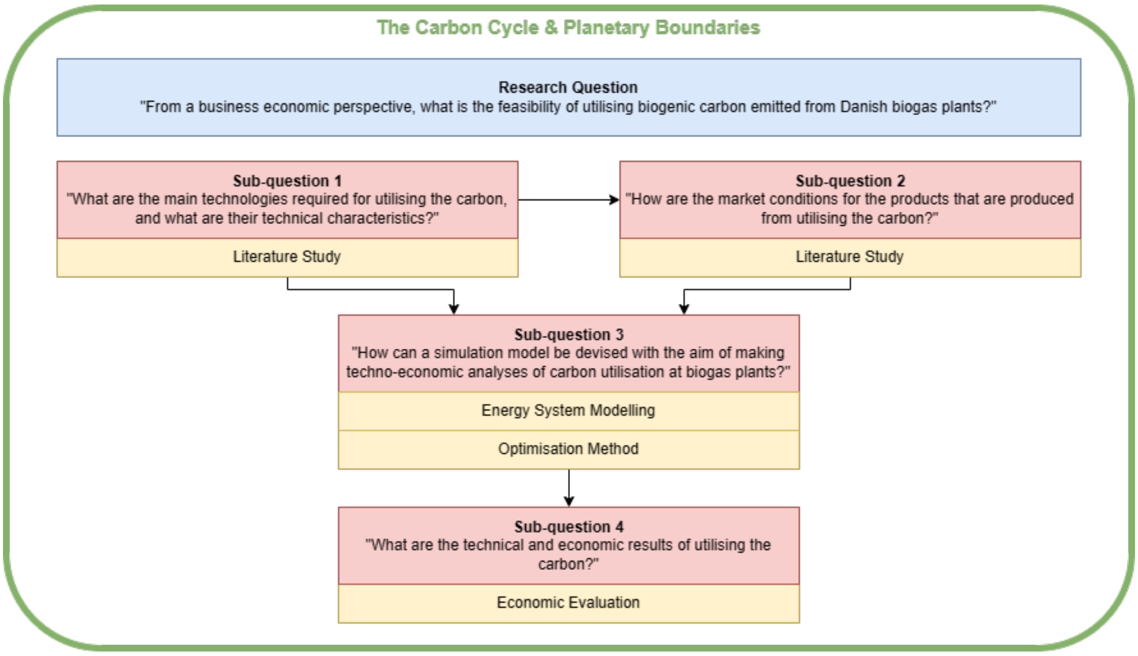

Figure 3.1. Visualisation of the research design

The theoretical framework is presented in Chapter 4 and consists of two theories. The carbon cycle explains, why it is important to differentiate between fossil carbon and biogenic carbon, while the planetary boundaries provide insight into, how critical the situation is. The methodology is described in Chapter 5. In Chapter 6, the technologies required for utilising the carbon from biogas plants are accounted for. The technologies enable production of liquid CO_2, e-methane, and e-methanol. The market conditions for these products are investigated in Chapter 7, where sub-question 2 is answered. Using the results of sub-question 1 and 2, a simulation model is devised to answer sub-question 3 in Chapter 8. Finally, the results of the simulations are compiled in Chapter 9 to answer sub-question 4.

3.1 State-of-the-art Research

The aim of this section is to review state-of-the-art research to describe, how this thesis builds on the latest research and creates new knowledge. This is further explained in Section 5.1. Scientific articles have been found by using search engines such as Primo (Aalborg University Library) and Elsevier.

Similarly to this thesis, Horschig et al. [2019] recognises the business case of utilising biogenic CO_2 from biogas plants and examines three utilisation pathways. The utilisation pathways are, however, not the same as in this thesis. As Germany is a large producer of biomethane, Horschig et al. [2019] uses Germany as a case, while this thesis uses Danish framework conditions. Horschig et al. [2019] focuses on, how the income from utilising the CO_2 can replace diminishing income from subsidy schemes and thus increase the total biomethane production in Germany. This thesis provides another perspective by focusing on the business economic considerations for the individual biogas plant instead of the impact on the national biomethane production. Finally, there has been a rapid technological development since the publication by Horschig et al. [2019].

Full et al. [2022] examines the climate effect of retrofitting the existing biogas plants in Baden-Wuerttemberg (Germany) for hydrogen production via steam methane reforming and storing the biogenic CO_2 by means of CCS. The business economic perspective for the biogas plants is, however, not included.

As it appears from Horschig et al. [2019] and Full et al. [2022], there are numerous pathways of utilising the biogenic CO_2 from biogas plants. This thesis examines three pathways that are often considered, which is CO_2 liquefaction, e-methane production, and e-methanol production. The innovative aspect of this thesis is that all three pathways are examined simultaneously using the same framework conditions. This provides a fair frame of reference. Scientific studies have so far examined the pathways individually, which complicate comparisons and makes it difficult to objectively assess the investment options for Danish biogas plants. The following are three examples of such studies, where the economic feasibility of respectively CO_2 liquefaction, e-methane production, and sustainable methanol production is examined individually:

- Vernersson [2022] examines the economic feasibility of CO_2 liquefaction at a biogas plant with a biomethane production capacity of 350 Nm^3.
- Sieborg et al. [2024] examines the economic feasibility of e-methane production at a biogas plant with a private wire to photovoltaics in California.

- Moioli og Schildhauer [2022] examines the economic feasibility of three different routes to sustainable methanol production using biogas.

These three examples demonstrate the varying framework conditions and assumptions between studies, which makes is difficult to get an overview of the business case for Danish biogas plants. This thesis overcomes that by having the same framework conditions for every pathway.

3.2 Delimitations

In this section, the delimitations of the analysis are outlined along with the reasons for making them. The purpose of the delimitations is to narrow down the scope of the analysis and point out, what could be subject to potential further study.

The first delimitation is that once the liquid CO_2, e-methane, or e-methanol is produced, it is no longer within the scope of the analysis. In the liquefaction scenario and the e-methanol scenario, it is impossible to predict the transport route from biogas plant to consumer, as the locations are unknown. Therefore, the cost of transport from producer to consumer is not included on the analysis. To make the scenarios comparable, the feeding tariff of the gas grid is, likewise, not included in the e-methane scenario.

The second delimitation is that the regulation ability of the units at the plant is only considered to a lesser extent. It is assumed that all units can regulate production on an hourly basis, which allows the plant to operate with low electricity prices, and avoid high electricity prices. While operation is flexible for the electrolysers and the electric boiler, it is more challenging for the liquefaction plant, the methanation plant, and the methanol plant [DEA, 2024b]. To include the specific regulation ability of each unit, a more comprehensive simulation model is required, so the delimitation is made to maintain the simplicity of the model and focus on other aspects of the analysis.

The third delimitation is that a hydrogen storage is not included in the e-methane scenario or e-methanol scenario. A hydrogen storage would allow the electrolysers to benefit from fluctuating electricity prices, while the methanation plant and the methanol plant would have more stable operation patterns. This would be more in line with the regulation abilities of the technologies, but it would also require a more complex simulation model with multiple production patterns in each scenario. Considering the workload of developing such a model, a hydrogen storage is not included in the analysis. This delimitation is further discussed in Section 10.3.2.

The fourth delimitation is that all of the available CO_2 from the biogas plant must be utilised. The business case of utilising CO_2 from biogas plants and thus the relevancy of this thesis relies on the commitment to climate goals. As biogenic CO_2 is a limited resource, it should be utilised to the fullest extent, where it is most cost-effective to have the greatest climate impact. From a climate perspective, it is therefore important to examine the business case of utilising all of the CO_2 from each biogas plant. This delimitation is further discussed in Section 10.3.1.

Theoretical Framework 4

In this chapter, the theoretical framework is presented, which will provide insight into the world view of this thesis. The theoretical framework is composed of two theories being the carbon cycle and planetary boundaries. Both theories will be explained, and the association with carbon management at biogas plants will be accounted for.

4.1 The Carbon Cycle

In terms of carbon emissions and global warming, it is worth highlighting the difference between biogenic carbon and fossil carbon. While there is no visible difference between the atoms, biogenic carbon is perceived as being climate neutral, whereas fossil carbon causes global warming. The reason for this seemingly irrational distinction is conceptualised in this section.

The global carbon cycle consists of different carbon reservoirs, where carbon is stored for various periods of time, before it is transferred to another reservoir. A fast and a slow domain can be identified within the global carbon cycle. The reservoirs in the fast domain are the atmosphere, bodies of water, vegetation and soils. It is called the fast domain, because the turnover time of the reservoirs is relatively short. In the atmosphere, the turnover time is a couple of years, while the turnover time in the other reservoirs is 10s to 1,000s of years. Even though it sounds like a long time, turnover time in the slow domain is even longer. The reservoirs in the slow domain are sediments and rocks, where turnover time is at least 10,000s of years. There are natural exchanges between the fast domain and the slow domain, but the exchanges are limited and constant over time. [Ciais et al., 2013]

There is a natural balance between the fast domain and the slow domain, which ensures that the atmosphere contains the right amount of carbon. Without any greenhouse gasses in the atmosphere, the global average temperature would drop to -18 °C [Stage, 2024]. Carbon in the atmosphere is thus a prerequisite for having livable conditions on Earth. However, when fossil fuels are combusted, large quantities of carbon are unnaturally transferred from the slow domain to the fast domain, which supersaturates the atmosphere with carbon and causes an increased global warming. It is therefore (fossil) carbon emissions from the slow domain that causes global warming, while (biogenic) carbon emissions from the fast domain merely forms part of a natural cycle. This makes biogenic carbon emissions climate neutral.

The CO_2 emitted from biogas upgrading is biogenic. So, when the CO_2 is utilised for production of e-fuels, the CO_2-emission following combustion is climate neutral, as the carbon remains in the fast domain. Additionally, e-fuels can contribute to keeping carbon in the slow domain by phasing out the use of fossil fuels. Likewise, when the CO_2 is stored underground, negative CO_2-emissions are created, as the carbon is transferred from the fast domain to the slow domain. This correlation is crucial for understanding the value and application of biogenic CO_2 versus fossil CO_2. It also underlines, why it is important from a societal point of view to make use of the biogenic CO_2 from biogas plants.

4.2 Planetary Boundaries

Around 10,000 years ago the latest ice age ended and the Holocene epoch began. During the Holocene epoch modern civilisation based on agriculture developed under warm and stable environmental conditions. However, due to human activity, these environmental conditions are now under pressure. Earth is resilient and tolerant of human impact to a certain degree. However, it will have severe and possibly irreversible consequences, if Earth is continuously damaged faster, than it can recover. [Richardson et al., 2023]

It must be in the best interest of humanity to preserve the environmental conditions that have allowed human welfare for so long. Therefore, nine planetary boundaries, which reflect the status of Earth's environmental system, have been identified. Each planetary boundary has one or two control variables, which indicate, weather the planetary boundary has been crossed. Likewise, each control variable has a safe operating space, where there is no risk of damaging Earth's environmental system. Six out of nine planetary boundaries have already been crossed including the planetary boundary for climate change. It should be noted that the planetary boundaries are interdependent, so that crossing one planetary boundary may trigger a domino effect. [Richardson et al., 2023]

The control variables for climate change are the CO_2 concentration in the atmosphere and the radiative forcing at the top of the atmosphere. Radiative forcing is a measure of the planetary energy exchange. A positive radiative forcing means that Earth absorbs more energy from the sun, than it releases. In that case global warming is thus on the rise. Prior to the industrialisation, the CO_2 concentration was 280 parts per million (ppm), and the radiative forcing was 0 W/m^2. The planetary boundary is set to be at 350 ppm and 1 W/m^2, while the control variables are currently at 417 ppm and 2.91 W/m^2. Furthermore, the control variables are increasing, when comparing to the previous evaluation from 2015. [Richardson et al., 2023]

The carbon cycle explains, why fossil CO_2-emissions cause global warming, and how biogenic CO_2 should be used as part of the solution. Combined with an understanding of planetary boundaries, it becomes evident that the need for action is urgent. The fact that the planetary boundary of climate change has already been crossed, does not mean that it is too late. It means that the risk of severely damaging Earth's environment is higher. With this in mind, it is clear that the control variables should be reduced to the safe operating space as soon as possible. With every day, where the planetary boundary is crossed, there is a risk of causing irreversible damage to Earth's environment.

Methodology 5

In this chapter, the four methods that are used to answer the sub-questions are described. The methods are literature review, energy system modelling, economic evaluation, and optimisation method.

5.1 Literature Review

A literature review has been conducted to answer sub-question 1 and sub-question 2. In Chapter 6, sub-question 1 is answered by using the Technology Catalogues published by the Danish Energy Agency. The Technology Catalogues provides technical and financial data on the technologies that enables the utilisation of CO_2 from biogas plants. In Chapter 7, sub-question 2 is answered by mapping the market conditions for liquid CO_2, e-methane, and e-methanol. The mapping is based on the behavior of market operators, scientific reports, and regulation by public institutions.

When conducting a literature review, it is important to take the time of publication, the credibility of the author, and the motivation behind the publication into consideration. As technologies and markets develop with time, recent publications are likely to be accurate, while older publications get increasingly outdated and therefore not applicable. The author must also have proven knowledge on the topic to be trustworthy. Finally, publications can be biased towards certain agendas and therefore not provide objective information. This critical thinking ensures that the literature is viewed in the right context, and that misinformation is not passed on.

Besides gathering knowledge for the analysis, the purpose of the literature review is to ensure that this thesis is state-of-the-art research. Consequently, existing research is reviewed to document that this thesis is not simply repeating existing knowledge. Answering the research question should create new knowledge to fill a knowledge gap in the existing research. The review of state-of-the-art research is carried out in Section 3.1. Furthermore, the research question should be relevant to answer and create valuable knowledge. The relevancy of the research question is accounted for in Chapter 2.

5.2 Energy System Modelling

This thesis relies on energy system modelling for the scenario development in Chapter 8. In this section the method of energy system modelling is described along with the pros and cons of using Excel.

When creating a model of an energy system, the aim is always to make it as realistic as possible to get the most useful results. However, it is impossible to completely replicate reality, which implies that the creator has to give priority to certain aspects, while other aspects are disregarded. The prioritising depends on the world view of the creator and the purpose of the model. It is therefore crucial to take the delimitations and assumptions into account, before ascribing value to the results. [Lund et al., 2017]

In this thesis, Excel is used as the modelling tool. Excel was chosen, because it allows the creator to build the model from scratch to fit the exact requirements for the analysis. One criteria was that scenario development should be quick, so that numerous scenarios could easily be developed. It should therefore be possible to change between variables such as technologies, electricity price distributions and selling prices with very few clicks.

The downside of using Excel is that it is a time-consuming process to build the model yourself, and the risk of typing errors increases, as there is more to type in. Compared to other programs, the Excel model might not be as user-friendly and intuitive, as users might not share the same logic as the creator. The upside of using Excel is that the creator has full understanding of the inner workings of the model, which makes it easier to analyse the results and call attention to inadequacies. When using other programs than Excel that have been designed by someone else specifically for energy system modelling, the model can, at first, appear as a black box, until the user gets familiar with the inner workings.

5.3 Economic Evaluation

The method behind the economic evaluation of the scenarios will be described in this section. The description features the key concepts of time value of money, discount rate, net present value, rate of return, and levelized cost of production. The method is used in Chapter 9.

Money holds the potential to earn more money through investments or interest. The value of money therefore decreases with time, as potential earnings are lost. Inflation also adds to decreasing value of money. As a result, a sum of money is worth more today, than it will be in the future. This concept is the **time value of money**. [Fernando, 2023]

Due to the time value of money, the present value of future earnings and expenses needs to be determined to accurately evaluate a project. This is called a discounted cash flow analysis and requires a **discount rate**. The discount rate is the annual rate of devaluation during the evaluation period, which means that a high discount rate will assign future cash flows low value and vice versa. The discount rate can be determined by the opportunity cost or the cost of capital, which varies from company to company. The sum of the initial investment and the discounted cash flows results in the **Net Present Value (NPV)**. A positive NPV indicates a profitable project, while a negative NPV indicates a unprofitable project. The NPV can thus be used to assess the economic feasibility of a project and prioritise investment options. [Hayes, 2023]

To solely use the NPV to evaluate a project does not provide the full picture, as the risk is not taken into account. A project with large cash flows is likely to have a higher NPV than a project with small cash flows. However, the project with large cash flows is naturally also associated with greater risk. To amend this inadequacy, the **Real Rate of Return**

(RRoR) will be calculated. In this thesis, the RRoR is calculated by dividing the NPV with the total discounted costs during the evaluation period. The RRoR is thus the net return expressed as a percentage of the total costs, and a high RRoR signifies a high profit compared to the costs. [Kenton, 2024]

The **levelized cost of production** is the average discounted cost of producing one unit during the evaluation period. In this thesis the levelized cost of liquid CO_2 (€/ton), e-methane (€/MWh), and e-methanol (€/ton) will be calculated. The levelized cost indicates the economic feasibility of the project, especially, when it is compared to the selling price. It can also be used to compare projects or scenarios with each other.

In this thesis, scenarios are economically evaluated by calculating the NPV, the RRoR, and the levelized cost of production. The evaluation period is 20 years (2025 to 2045) with a 5% discount rate, and the initial investment is happening in 2025. Scrap values are counted as income in 2045 and calculated by linear depreciation throughout the technical lifetime of the asset.

5.4 Optimisation Method

In Chapter 8, an Excel model is devised to simulate scenarios, where CO_2 from biogas plants is utilised to produce liquid CO_2, e-methane, or e-methanol. As part of the simulation, operation and capacity of the production plant are economically optimised. This section describes the optimisation method.

When the annual amount of available CO_2 or biogas is entered into the model, it is assumed that the entirety of the entered amount will be utilised. This makes the capacity and the number of full load hours interdependent. If the capacity is increased, the number full load hours is automatically reduced accordingly and vice versa. This interdependency enables the capacity and the number of full load hours to be decided by the kip price.

The optimisation is conducted by determining the kip price that provides the highest NPV. The kip price is a term for the highest electricity price (including electricity tariffs) during hours of operation in a year. This means that the plant is in operation during hours, where the electricity price is lower or equal to the kip price, and the plant is not in operation during hours, where the electricity price is higher than the kip price. A low kip price therefore entails few full load hours and a high capacity, whereas a high kip price entails many full load hours and a low capacity. With this correlation, the kip price that provides the highest NPV, can be identified.

The kip price that provides the highest NPV is found by What-If Analysis in Excel. A table with two columns is made. The first column contains all the possible kip prices, and the second column contains the corresponding NPV's. Conditional Formatting enables Excel to highlight the highest NPV, and the corresponding kip price is then located next to the highlighted cell. The table automatically updates, when changes that influence the NPV are made. Figure 5.1 shows an example of the correlation between the kip prices and the NPV's in the e-methanol scenario. The kip price that provides the highest NPV is 119 €/MWh, which results in 6,457 full load hours and a NPV of 23 million €.

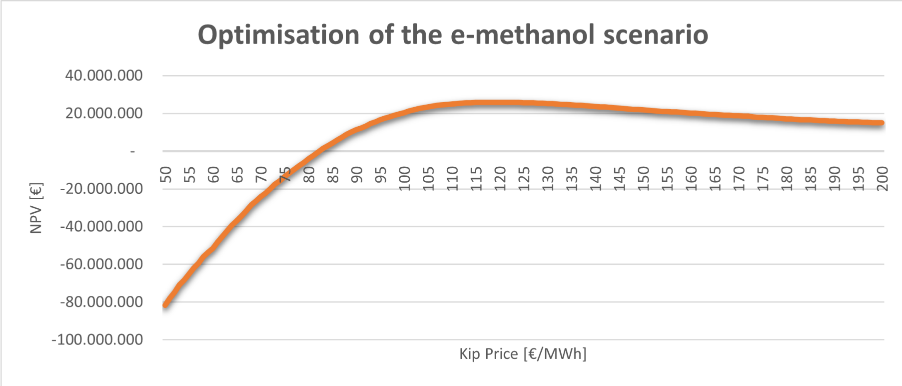

Figure 5.1. Optimisation of the e-methanol scenario by What-If Analysis

There is, however, a restriction to this optimisation. All of the technologies (except the intermediate storage) have a maximum number of full load hours due to outages. If the plant has more full load hours than one of the chosen technologies can handle, the model will show an error. The maximum number of full load hours for the technologies can be found in Appendix C.

The Excel Solver was considered as an alternative optimisation method to What-If Analysis. However, it was found that the Solver was either too slow or too imprecise (depending on the settings) to be useful. For that reason, What-If Analysis was selected as the optimisation method instead.

Technology Descriptions 6

The aim of this chapter is to answer the first sub-question:

What are the main technologies required for utilising the carbon, and what are their technical characteristics?

The sub-question is answered by accounting for the technical characteristics of the technologies. This implies that the financial data regarding the technologies will not be presented in this chapter. The technologies are liquefaction of CO_2, catalytic and biological methanation, e-methanol synthesis, and the three main types of electrolysis. The technology descriptions are based on the Technology Catalogues published by the Danish Energy Agency (DEA) and focuses on technical requirements for usage, inputs and outputs, and technology maturity [DEA, 2024b]. This should provide a sufficient basis for understanding the technologies that are addressed in this thesis. All heating values are given as lower heating values.

By describing these technologies, three pathways are outlined, which the management of a biogas plant can take to utilise the biogenic carbon. The first pathway is to liquefy and sell the carbon, the second pathway is to produce e-methane to supplement the production of biomethane, and the third pathway is to produce e-methanol.

6.1 Liquefaction

When CO_2 is transported by tanker truck it is liquefied to optimise the use of space available. Therefore, if the management at a biogas plant wishes to sell CO_2, a liquefaction plant must be installed to prepare the CO_2 for transport.

Before CO_2 can be liquefied, it must be purified with a charcoal filter and a scrubber. When upgrading biogas to biomethane, the CO_2 is separated from the methane along with other impurities. These impurities, such as hydrogen sulfide, volatile organic compounds and water, must be removed from the CO_2 prior to liquefaction. Otherwise, they can obstruct operation, damage the equipment and reduce the quality of liquefied CO_2. Once the CO_2 is purified, it is pressurised and cooled to 25 °C in preparation for liquefaction. Just before liquefaction, any remaining water is removed in the dehydrator. The liquefaction is conducted in a heat exchanger with ammonia used as cooling fluid. The liquid, which is now almost entirely CO_2, is then lead to a distillation column for the final purification. Figure 6.1 shows an illustration of the liquefaction process. [DEA, 2023b]

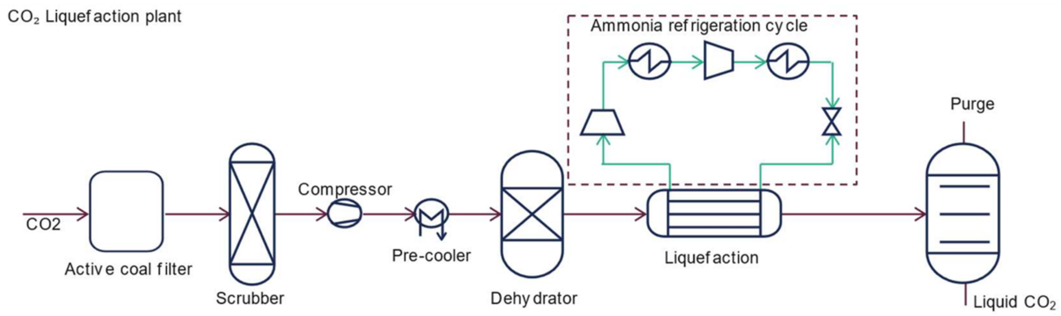

Figure 6.1. A typical liquefaction process
[DEA, 2023b]

CO_2 can be liquefied at various conditions, however, to comply with industrial standards it must be pressurised to 15-20 bar and cooled to -25 to -30 °C. More specifically, it is typically 15 bar and -28 °C.

Table 6.1 shows the inputs and outputs of liquefaction. The electricity is mostly used for cooling and pressurisation. The temperature of the excess heat varies in temperature depending on the source. Approximately half of the excess heat is 80 °C, while the other half is 50 °C or colder. [DEA, 2023c]

Inputs	**Outputs**
1 ton CO2 stream	1 ton liquefied CO2
133 kWh Electricity	343 kWh Excess Heat
	17 kg water

Table 6.1. Simple input-output model for a liquefaction plant in 2025
[DEA, 2023c]

Liquefaction is a mature technology with a Technology Readiness Level (TRL) of 9 and, therefore, fundamental future improvements are not expected. However, efforts are made to increase the energy efficiency and lower the operational costs. Due to outages a liquefaction plant has a maximum limit of 8,308 full load hours. [DEA, 2023b]

6.2 Methanation

Instead of selling the liquefied CO_2, it can be utilised to produce e-methane. CO_2 can react with hydrogen to create e-methane also known as synthetic natural gas (SNG) [DEA, 2024e]. This reaction is called methanation, and the reaction equation is as follows:

$$CO_2 + 4H_2 \Rightarrow CH_4 + 2H_2O$$

The conventional pathway to methanation is catalytic methanation, which was discovered in 1902 and has been used to convert coal into gas at large scale. Therefore, the challenges with catalytic methanation is to reduce the scale to fit with biogas plants and to increase the regulation ability to accommodate an intermittent production of green hydrogen. Catalytic methanation can be done at below 200 °C and 1 bar or at 300 °C and 20 bar to achieve a conversion rate of more than 98%. [DEA, 2024e]

Another pathway that has been developed during the last 10 years is biological methanation. While catalytic methanation is based on a chemical catalyst, biological methanation uses microorganisms instead. Contrary to catalytic methanation, biological methanation has yet only been demonstrated on small scale, however, it is expected that full scale projects will be undertaken during the next few years. [DEA, 2024e]

There are various options for integrating a methanation plant with an existing biogas plant. The methanation reactor can be supplied with either raw biogas directly from the digester or CO_2 emitted from the upgrading plant. This means that the methanation reactor can be placed both upstream or downstream from the upgrading plant. Data even suggests that the output of the reactor can be grid quality methane, which would make the upgrading plant dispensable. In this thesis, the methanation reactor for both biological and catalytic methanation is placed upstream from the upgrading plant. This ensures that any residual CO_2, there might be, will be removed before the methane enters the grid. It also entails that the methanation reactor is supplied with biogas instead of CO_2. [DEA, 2024e]

As biological methanation is also occurring in the digester of the biogas plant, it is possible to inject hydrogen directly into the digester (in-situ) instead of having a separate methanation reactor (ex-situ). In-situ methanation has lower capital investments, but as the methanation does not take place in a separate reactor, it is more difficult to fully control. Additionally, in-situ methanation has yet only been accomplished in pilot projects and, therefore, there are fewer suppliers. The methane concentration in the gas leaving an ex-situ reactor is around 95-97% or higher, while it is only 80% with in-situ. For these reasons, ex-situ has been chosen for both biological and catalytic methanation. Figure 6.2 illustrates, how the biological and catalytic methanation reactors will be integrated with the biogas plant. [DEA, 2024e]

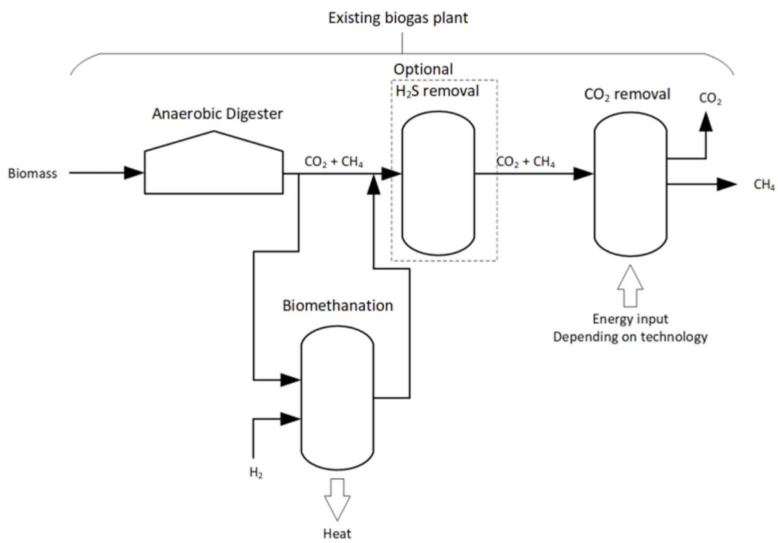

Figure 6.2. Integration of a methanation reactor with an existing biogas plant [DEA, 2024e]

Table 6.2 shows the inputs and outputs of biological methanation and catalytic methanation. Both methanations are ex-situ and supplied with biogas from the digester. The original data provided by DEA [2024d] has been converted to more tangible and comparable units using the DEA's standard factors [DEA, 2024i].

Biological Methanation (2025)		Catalytic Methanation (2020)	
Input	**Output**	**Input**	**Output**
100 Nm3 Biogas	82 Nm3 Methane	100 Nm3 Biogas	98 Nm3 Methane
(0.64 MWh Biogas)	(0.92 MWh Methane)	(0.64 MWh Biogas)	(1.07 MWh Methane)
0.50 MWh Hydrogen	0.19 MWh Excess Heat	0.55 MWh Hydrogen	0.12 MWh Excess Heat
0.02 MWh Electricity		0.01 MWh Electricity	

Table 6.2. Simple input-output models for biological methanation and catalytic methanation in respectively 2025 and 2020
[DEA, 2024d] and [DEA, 2024i]

It appears from Table 6.2 that biological methanation has an energy efficiency of 79%, while catalytic methanation has an energy efficiency of 89% [DEA, 2024d]. Due to the significant difference in reactor temperature, biological methanation will produce excess heat at 50-60 °C, while excess heat from catalytic methanation will be more than 100 °C [DEA, 2024e]. Biological methanation has a maximum limit of 8,322 full load hours, while it is 8,396 full load hours for catalytic methanation [DEA, 2024d].

6.3 E-methanol Synthesis

Fossil methanol is conventionally produced from coal or natural gas. As a substitute for fossil methanol, e-methanol can be produced with biogenic CO_2 and renewable hydrogen as feedstocks. The synthesis takes place in a reactor at 200-300 °C and 50-100 bar and consists of two reactions [DEA, 2024e]. The reaction equations are as follows:

$$(1)\ 3H_2 + CO_2 \Rightarrow CH_3OH + H_2O$$
$$(2)\ H_2 + CO_2 \Rightarrow CO + H_2O$$

The output of the reactor is used to preheat the reactants before entering the reactor, and the unreacted gasses are purged or recycled. The remaining mixture of methanol, water and byproducts (including CO) is distilled to separate the methanol. It is assumed that the hydrogen and the CO_2 are injected into the reactor at 5 °C and respectively 70 bar and 100 bar. The heat is delivered as steam to the reactor at 184 °C, after which it is used to heat the distiller. The excess heat from the distiller is 50-100 °C. The energy efficiency of the process is 78%, and the maximum limit of full load hours is 8,389. Table 6.3 shows the inputs and outputs of the e-methanol synthesis.

Inputs	Outputs
1.4 ton CO2	1 ton Methanol
0.19 ton Hydrogen	0.22 MWh Excess Heat
(6.4 MWh Hydrogen)	0.55 ton Water
0.1 MWh Electricity	
0.58 MWh Heat	

Table 6.3. Simple input-output model for production of e-methanol in 2025 [DEA, 2024d]

Conventional methanol production has a TRL of 9, and production of e-methanol is based on the same technology. The difference is among others that conventional methanol relies on dispatchable fossil fuel, while e-methanol relies on the intermittency of hydrogen production. Therefore, research and development is focused on increasing the regulation ability of the e-methanol plant to make operation more flexible. [DEA, 2024e]

6.4 Electrolysis

It is evident from Section 6.2 and Section 6.3 that green hydrogen is needed to produce respectively e-methane and e-methanol. Green hydrogen is produced, when renewable energy is used to split water into oxygen and hydrogen [DEA, 2024e]. This reaction is called electrolysis, and the reaction equation is as follows:

$$2H_2O \Rightarrow 2H_2 + O_2$$

There are three main types of electrolysers being Alkaline Electrolysis Cell (AEC), Proton Exchange Membrane Electrolysis Cell (PEMEC) and Solid Oxide Electrolysis Cell (SOEC). The electrolysers uses different techniques, where some are closer to being fully developed than others, to separate the hydrogen and oxygen. This results in different technical characteristics for each type of electrolyser. [DEA, 2024e]

Electrolysis requires a substantial amount of water, and the water needs to be purified beforehand. The purification improves the conductivity of the water, and impurities can contaminate the system. The water treatment consists of a pre-treatment and a polishing. The pre-treatment depends on the water source, and different water sources requires more or less water. To produce 1 m^3 purified water, 1.4 m^3 groundwater, 1.5 m^3 surface water or wastewater, or 3.3 m^3 seawater is needed. The polishing depends on the type of electrolyser. PEMEC needs ultrapure water, while AEC and SOEC, in comparison, can operate with less pure water.

While AEC and PEMEC are supplied with water, SOEC requires water in the form of steam, and thus, around 1/5 of the energy consumption for SOEC is heat. SOEC operates at over 600 °C, however, as SOEC consumes heat, there is no recoverable excess heat. AEC and PEMEC operates at respectively 50-80 °C and 60-80 °C, and the recoverable excess heat is 50-70 °C. The outputs for all three types of electrolysers are hydrogen and oxygen. There is currently a market for oxygen, however, with Power-to-X projects becoming increasingly prevalent, it is possible that the market will be saturated. [DEA, 2024e]

In terms of regulation ability, electrolysers are flexible and expected to be able to adjust operation to fluctuating electricity prices. The start-up time depends on, weather it is a cold or a warm start-up. A warm start-up means that the electrolyser has been kept at operating temperature and pressure, and a cold start-up means that the electrolyser is at ambient temperature and pressure. PEMEC is the most flexible electrolyser, while the SOEC is the least flexible. [DEA, 2024e]

The raw materials for SOEC are both abundant and cheap, which is an advantage regarding upscaling and commercialisation of the technology. In comparison, AEC uses some expensive and scarce materials, and especially nickel is expected to be in short supply during the next decades. A potential solution is to substitute the pure nickel with nickel plated carbon steel. PEMEC has the most difficulties in terms of the raw materials, which are both rare and expensive. In the long term, this constitutes a barrier for development of PEMEC projects. [DEA, 2024e]

Table 6.4 provides an overview of technical characteristics regarding the three types of electrolysers. Overall, AEC is the most mature technology, while SOEC has not yet reached commercialisation. This also indicates that SOEC has the greatest potential for further research and development.

	AEC	**PEMEC**	**SOEC**
Energy Efficiency	58.7%	55%	67.4%
Electricity Share of Input	100%	100%	79.5%
Heat Share of Input	0%	0%	20.5%
Water Consumption	0.175 ton / MWh Input	0.167 ton / MWh Input	0.228 ton / MWh Input
Water Purity	Pure	Ultrapure	Pure
Operating Temperature	50-80 °C	60-80 °C	$>$ 600 °C
Excess Heat	0.264 MWh / MWh Input	0.307 MWh / MWh Input	0 MWh / MWh Input
Cold Start-up Time	$<$ 80 minutes	30 seconds	600 minutes
Warm Start-up Time	240 seconds	$<$ 10 seconds	600 seconds
Raw Materials	Somewhat expensive and scarce	Critically expensive and rare	Cheap and abundant

Table 6.4. Comparison of the three types of electrolysers in 2025

Research and development for AEC is focused on increasing the energy efficiency while maintaining the use of inexpensive raw materials. For SOEC, researchers are trying to reduce costs and find alternative raw materials to substitute the current ones that are expensive and rare. As SOEC is the least mature technology efforts are put into upscaling the technology. Furthermore, if the operating temperature could be lowered, it would be possible to use even cheaper raw materials, which would reduce the cost. [DEA, 2024e]

Market Conditions 7

The aim of this chapter is to answer the second sub-question:

How are the market conditions for the products that are produced from utilising the carbon?

The sub-question is answered by investigating the market conditions for the products produced by the technologies, which are described in Chapter 6. The products are, thus, liquefied CO_2, e-methane and e-methanol. The global market demand and applications of liquefied CO_2 are described, and the selling price is analysed. The selling price of e-methane is, likewise, analysed along with biogas certificates and relevant subsidy schemes. The global market demand and applications of e-methanol is accounted for, and current and future selling prices are estimated.

7.1 Liquid CO2 Market

In this section, the market conditions for CO_2 will be investigated. This entails an analysis of the global market development in terms of demand and application. Lastly, the selling price of liquefied biogenic CO_2 will be discussed.

7.1.1 Global Market Demand

Aside from being a greenhouse gas, CO_2 is also a commodity that is traded and have various applications. In 2015, the global demand for CO_2 was 230 million tons annually. Most of the CO_2, was used for production of urea (130 million tons) and Enhanced Oil Recovery (EOR)[1] (70-80 million tons). The pie chart on Figure 7.1 shows the different applications for CO_2 in 2015, and how much of global demand they each represent The demand is primarily from North America (33%), China (21%) and Europe (16%). It can also be seen from the bar chart on Figure 7.1 that the global CO_2 demand is expected to have an annual growth rate of 1.7% towards 2020 and 2025. [IEA, 2019]

[1]Enhanced Oil Recovery is a term for the various ways of recovering additional oil from reservoirs, when the easy-to-produce oil has been recovered. Through an injection wellbore, CO_2 can be injected into the reservoir, and when the CO_2 expands, oil is pushed towards the production wellbore. [US Department of Energy, 2022]

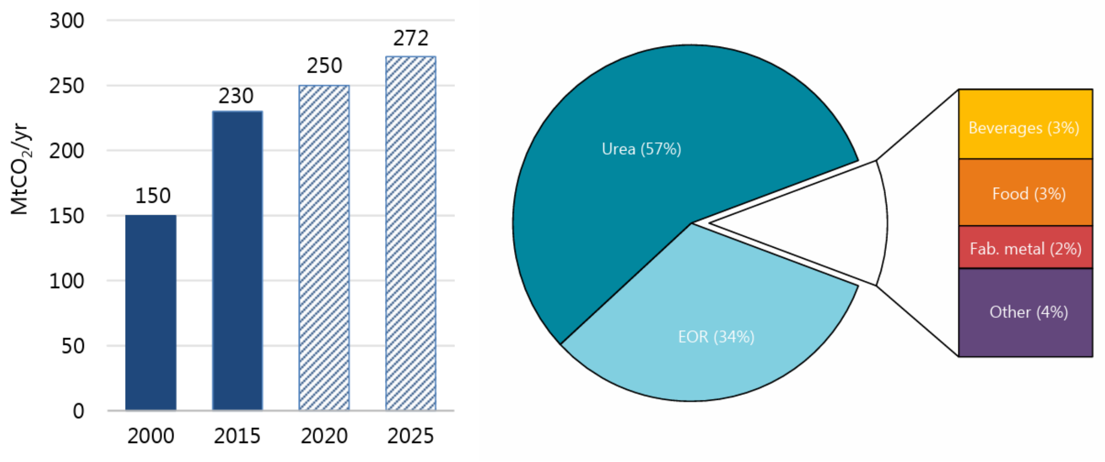

Figure 7.1. The global CO_2 demand in 2015
[IEA, 2019]

According to a more recent study, the global CO_2 demand will be 600 million tons in 2030 and 6,100 million tons in 2050 [Galimova et al., 2022]. In comparison, this entails annual growth rates of 17.1% (2025-2030) and 12.3% (2030-2050). It should, however, be noted that due to the maturity of the technologies and the dependence on framework conditions (e.g. energy policies and prices) there is much uncertainty connected with these projections. Projections for 2030 can range from 1,000 million tons all the way to 7,000 million tons based on the underlying assumptions [IEA, 2019].

7.1.2 Applications

The growing CO_2 demand can be ascribed to new emerging markets driven by a desire to fulfil various climate goals and mitigate global warming. One of these markets is the e-fuel market, where CO_2 is combined with hydrogen to produce renewable fuels that can substitute fossil fuels in hard-to-abate sectors. This could for instance be e-methane or e-methanol that are produced using the technologies described in Chapter 6. A barrier in this market is the cost of electricity, which typically constitutes 40-70% of production costs and makes it difficult for e-fuels to compete with fossil fuels. [IEA, 2019]

Other emerging markets are chemical production, building materials, and crop cultivation. Polymers are chemicals that are used in plastic, resins and foams. When producing polymers, the fossil fuel consumption can be reduced by adding pure CO_2 instead. Compared to e-fuel production, this is a much less energy-intensive process, which makes it cost-competitive with the conventional production pathway. In the construction industry, CO_2-cured concrete is cheaper, has better performance, and the carbon footprint is lower compared to conventional concrete. The carbon footprint and costs are lower, as CO_2-cured concrete requires less cement than conventional concrete. CO_2 can also be used in production of other building materials. Finally, the yield from crops in greenhouses can be increased by 25-30%, when CO_2 is added. [IEA, 2019]

Table 7.1 shows the global CO_2 demand of various utilisation pathways according to two different sources. Each pathway has a low estimate and a high estimate for its global

CO_2 demand in 2050. This provides a perspective on, how the CO_2 demand might be distributed in 2050. The list is, however, not exhaustive, as more pathways exists. One of the sources estimates that the total global CO_2 demand will be 2,000-8,000 million tons in 2050 [National Academies, 2023]. As the estimate also suggests, the source explicitly mentions that there is much uncertainty regarding projections of the future CO_2 demand. The estimate is, however, in line with the aforementioned projection of 6,100 million tons in 2050 [Galimova et al., 2022]. It appears from Table 7.1 that especially renewable fuels and construction materials will be large markets for CO_2 in 2050.

	[Hepburn et al., 2019]	**[National Academies, 2023]**
Chemicals	300-600 million tons	135-565 million tons
Renewable Fuels	1,000-4,200 million tons	700-2,100 million tons
Concrete	100-1,400 million tons	N/A
Construction Materials	N/A	900-5,000 million tons
EOR	100-1,800 million tons	N/A

Table 7.1. Global CO_2 demand of various pathways in 2050

Instead of utilisation, CO_2 can also be can be permanently stored underground to create negative emissions or produce blue hydrogen[2]. The International Energy Agency (IEA) highlights Carbon Capture and Storage (CCS) as a crucial technology for fulfilling climate goals, including the Paris Agreement [IEA, 2019].

7.1.3 Pricing

The selling price of liquefied CO_2 varies dependent on the distance from the producer to the consumer. Due to the cost of transport, the selling price is higher, when the producer is located closer to the consumer. Agriportance is a German company that trades liquefied biogenic CO_2, and Figure 7.2 shows Agriportance's market price estimates. There is a high and a low estimate for production close to the consumers, and a high and a low estimate for production far from the consumers. Locations close to consumers would for example be Bavaria or Hamburg, while locations far from consumers would for example be eastern Germany. [Agriportance, 2024a]

[2] Where green hydrogen is produced with electrolysis using renewable electricity, blue hydrogen is produced with steam reforming of natural gas, where the CO_2 is captured and permanently stored underground.

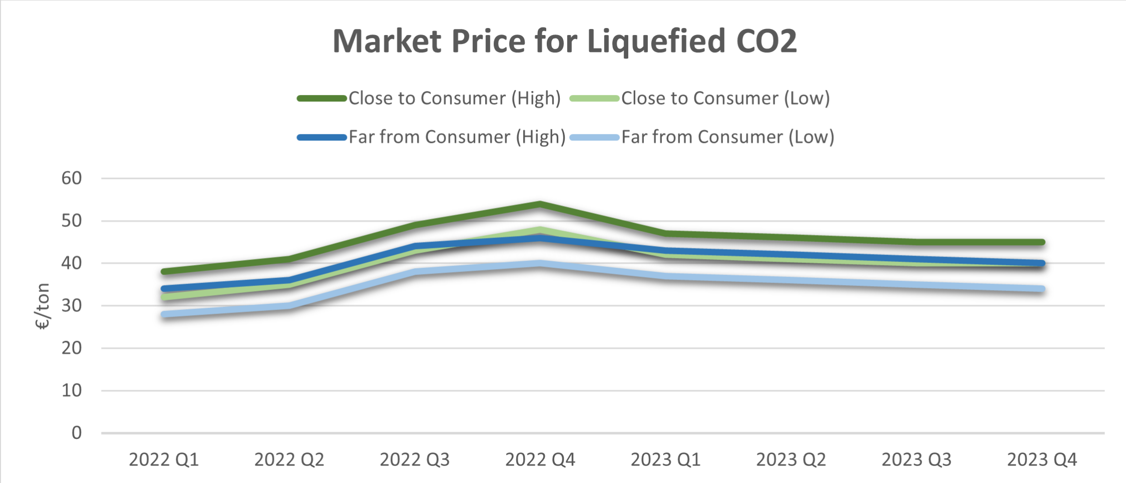

Figure 7.2. Estimates of the market price for liquid CO_2
[Agriportance, 2024a]

It appears from Figure 7.2 that the average market price for liquefied biogenic CO_2 during the last two years has been around 40 €/ton in Germany. However, according to the interview with Anders Søgaard Kristensen, who is a manager at Rambøll Management Consulting, the selling price of liquefied biogenic CO_2 might be higher. The interview is attached as Appendix B. During the interview, Kristensen mentions that he has encountered prices of 55-85 €/ton in connection with a project.

Based on the analysis of the market development for CO_2, the demand for biogenic CO_2 is expected to grow dramatically towards 2050. As biogenic CO_2 is also a finite resource, it would be a reasonable outcome that the price of biogenic CO_2 increases in the future. This deduction does, however, also depend on the development of the technologies for carbon capture.

7.2 E-methane Market

There is currently only one biogas plant in Denmark that produces e-methane. The plant is located on Als, and was put into operation in November 2023. At full load, the plant is expected to additionally produce 12,000 m^3 e-methane per day by means of biological methanation. The plant required an investment of 13.4 million € in a combined effort from Nature Energy and Andel. [Nature Energy, 2023]

When methane is produced from biogas plants, it is injected into the gas grid and transported to the consumers. The gas grid carries biomethane, e-methane and natural gas. Once the gasses are in the gas grid, they all have the same properties, and the only difference is their origin. Figure 7.3 shows, the share of methane that has been supplied to the gas grid from biogas plants and subsequently consumed. The remaining share is natural gas. It can be seen from Figure 7.3 that biogas plants during the last year have supplied more than a third of the content that has passed through the gas grid. [Energinet, 2024b]

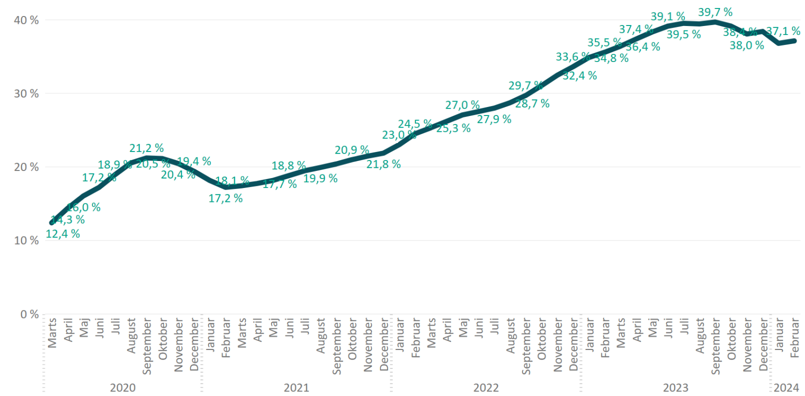

Figure 7.3. The share of methane from biogas plants in the gas grid [Energinet, 2024b]

The gas grid consists of a transmission grid and distribution grids. Energinet owns and operates the transmission grid, while Evida owns and operates the distribution grids. To use the gas grid, the owner of the biogas plant must first sign a connection agreement with the owner of the grid in question (either Energinet or Evida) [Energinet, 2024e]. There is currently 65 biogas plants connected to the gas grid in Denmark [Energinet, 2024a].

Once the biogas plant is connected to the gas grid, the methane can be sold on the gas market at the spot price. Figure 7.4 shows, how the gas market price has fluctuated during the last four years. In 2023, the average market price was 3.84 DKK/m^3 (46.78 €/MWh). [Biogas Danmark, 2024]

Figure 7.4. The market price of gas [Biogas Danmark, 2024]

In Appendix B, Kristensen explains that despite the recent volatility in the market, he expects the gas price to stabilise around 25-30 €/MWh (2.05-2.46 DKK/m^3).

7.2.1 Biogas Certificates

Apart from the market price of gas, biogas plants can generate income from selling biogas certificates[3], which document that the gas supplied to the grid is renewable. Companies

[3] The formal Danish word for biogas certificates is *oprindelsesgarantier*.

can then buy the gas from the grid as well as the biogas certificate to document that their gas consumption is sustainable. [Biogas Danmark, 2023]

Energinet is responsible for issuing biogas certificates to biogas plants, which is done on a monthly basis. The owners of the biogas plants can then choose to sell the biogas certificates directly to companies for consumption or hire a broker to handle the sales on their behalf. When a biogas certificate is sold to a company, the biogas certificate is deleted in Energinet's registry. This ensures that a biogas certificate can only be sold once. Every biogas certificate represents 1 MWh, and concurrently with more methane being supplied to the grid, more biogas certificates are being issued. In 2023, almost 8 million biogas certificates were issued, and the number is steadily increasing every year. In comparison, a little more than 2 million biogas certificates were issued in 2018. [Energinet, 2024c]

Figure 7.5 shows the annual sale of biogas certificates. If a biogas certificate is sold to a company outside Denmark, the biogas certificate is deleted, when it is transferred to the biogas certificate registry in that country. It can be seen that in 2023 only 13% of the biogas certificates were sold to Danish companies. In 2023, 36% were transferred to the German registry (DENA), 31% were transferred to Sweden, and the remaining 20% were transferred to other European countries. The same pattern can be seen in 2022 and 2021, where the majority of biogas certificates are transferred to Germany and Sweden. [Energinet, 2024c]

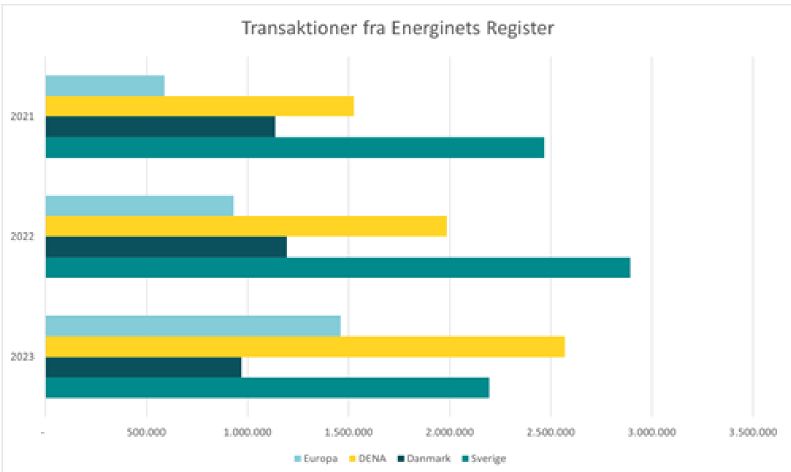

Figure 7.5. Biogas certificate sales
[Energinet, 2024c]

Germany and Sweden have high CO_2-taxes, and companies are reimbursed for the CO_2-tax, if they buy unsubsidised biogas certificates[4]. This increases the economic incentive to buy biogas certificates. The same incentive is not present in Denmark, where the CO_2-tax is lower, and companies are not reimbursed, when buying biogas certificates. That explains the massive export of biogas certificates to Germany and Sweden. In addition, Germany has higher CO_2 displacement requirements in the transport sector, which furthermore increases the demand for unsubsidised biogas certificates. [Biogas Danmark, 2023]

[4]An unsubsidised biogas certificate presupposes that the production of the methane has not been subsidised.

The market price of a biogas certificate depends on the sustainability certificate that accompanies it. The sustainability certificate is prepared by an EU-accredited auditor, and it documents the used biomass resources and other circumstances that influence the carbon footprint of the methane [Biogas Danmark, 2023]. Frank Rosager, who is the CEO of Biogas Danmark, believes that biogas certificates for e-methane will be worth the same as biogas certificates for biomethane produced from manure. The interview with Rosager is attached as Appendix A. Figure 7.6 shows an estimate of the market price of biogas certificates for biomethane from manure [Agriportance, 2024b].

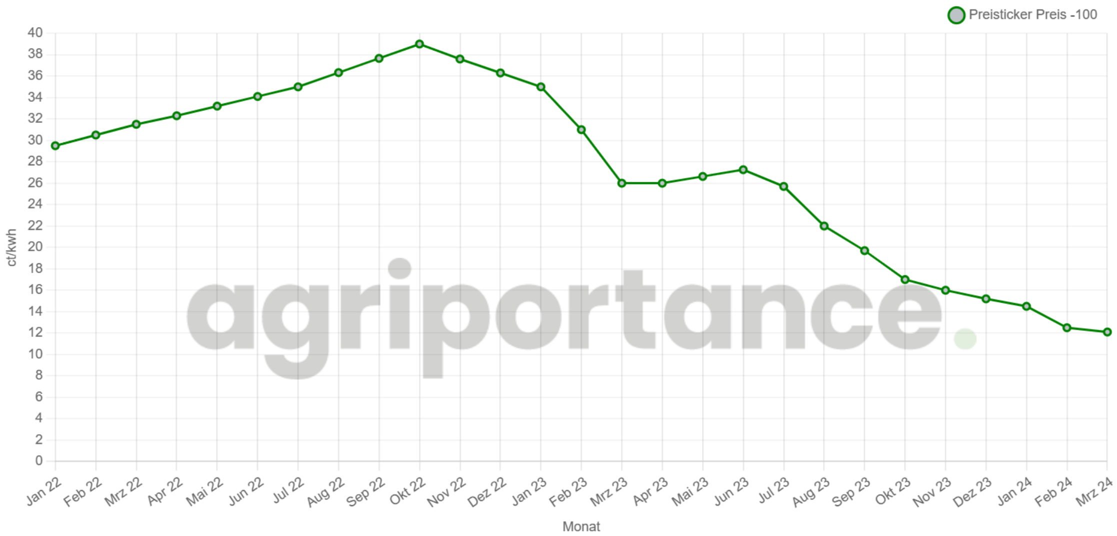

Figure 7.6. The market price of biogas certificates for biomethane from manure [Agriportance, 2024b]

It can be seen on Figure 7.6 that the market price of biogas certificates for biomethane from manure peaked at 390 €/MWh in October 2022, but since it has dropped to 121 €/MWh in March 2024. In Appendix A, Rosager explains that the recent price decrease is due to a Chinese disruption of the market with palm oil. He is, however, not expecting that the disruption will have a lasting effect on the market.

7.2.2 Subsidies for biomethane and e-methane

One of the objectives of the energy agreement in 2012 was to increase biogas production and increase the usage of biogas in other sectors than combined heat and power. To achieve this, it was decided that for every MWh of biomethane that was supplied to the grid, the producer should receive a subsidy of 55.55 €. The subsidy was, originally, comprised of three different contributions. There was a basis contribution of 38.16 €/MWh. Then there was a natural gas contribution of 12.56 €/MWh, which was inversely proportional with the natural gas price. For example, if the natural gas price rose by 5 €/MWh, the natural gas contribution would be reduced by 5 €/MWh and vice versa. This was done to ensure that biomethane could compete with natural gas prices and, at the same time, prevent overcompensation. Finally, there was a third contribution of 4.82 €/MWh, which was gradually phased out from 2016-2020. However, as this subsidy scheme was aimed at biomethane production, it does not apply to production of e-methane. [KEFM, 2012]

Today, the basis contribution is annually adjusted according to an index, and the basis contribution is reduced, if overcompensation is observed. The a natural gas contribution is also still in use, while the third contribution was phased out in 2020, as described in the passage above. Table 7.2 shows, how the subsidy has been adjusted from 2019-2024. It can be seen from the table, how the natural gas contribution has been 0 €/MWh since 2022 due to high natural gas prices. Furthermore, due to overcompensation, the basis contribution will be reduced by 1.84 €/MWh for the next three years from the 1st of March 2024 to the 28th of February 2027. In summary, the table shows that the biomethane subsidy has been fluctuating between 40-65 €/MWh during the last six years. [DEA, 2024j]

	2019	**2020**	**2021**	**2022**	**2023**	**2024**
Basis Contribution [€/MWh]	39.71	39.89	40.00	40.36	42.19	43.24
Natural Gas Contribution [€/MWh]	11.30	21.17	24.98	0	0	0
TOTAL SUBSIDY [€/MWh]	51.01	61.06	64.98	40.36	42.19	43.24

Table 7.2. The biomethane subsidy rates from 2019-2024
[DEA, 2024j]

Since the 1st of January 2020, it has no longer been possible to apply for the biomethane subsidy. However, with a more recent energy agreement in 2018, it was decided that biogas plants, which has already been granted the biomethane subsidy, will retain the subsidy for a minimum of 20 years, from when it was granted. [DEA, 2024a]

To replace the biomethane subsidy scheme, the Danish Energy Agency are preparing the framework conditions for the new subsidy scheme, which will subsidise production of both biomethane and e-methane. Instead of having a consistent subsidy, where every producer is granted the same amount, the new subsidy scheme is based on competitive bidding. This means that every applicant will submit an offer, and the lowest offers will be granted a subsidy, until the allocated funds are spend. Therefore, the applicant also has to specify the maximum amount of methane that the applicant wants the subsidy to cover. The hope is that this will increase competition and ensure that more methane is produced with smaller subsidies. [DEA, 2024f]

When a subsidy is granted, the applicant will have to sign a contract specifying the terms and conditions for receiving the subsidy. The contract lasts for 20 years, and the applicant can not receive both the subsidy and biogas certificates for the same methane. To be eligible for the subsidy, the production capacity has to be new, which means that the reactor and/or the electrolyser must not have been in use before. Finally, as a safeguard against overcompensation, the subsidy will be reduced equivalently, if the gas price exceeds 57.89 €/MWh. [DEA, 2024f]

The subsidy scheme is comprised of five tenders, which are shown on Table 7.3. For each tender, the table shows, what year the bidding round will be held, what year the payment and thus production will begin, and the allocated funds. As it is a competitive bidding process, it is uncertain, what the subsidy will be per MWh, and the subsidy will vary from applicant to applicant. [DEA, 2024f]

	1st Tender	2nd Tender	3rd Tender	4th Tender	5th Tender
Year of Bidding Round	2024	2026	2027	2028	2029
Year of First Payment	2024	2027	2028	2029	2030
Tender Amount [million € / year]	46.54	11.80	11.80	14.22	13.95

Table 7.3. The five tenders for biomethane and e-methane subsidies
[DEA, 2024f]

In Appendix A, Rosager comments on the new subsidy scheme. Due to the fact that biogas plants in the new subsidy scheme can not receive both a subsidy and a biogas certificate, he is convinced that biogas plants will focus on unsubsidised biogas certificates, as they are worth more than the subsidy. Unsubsidised biogas certificates are also worth more than subsidised biogas certificates, as they can be used to fulfil the CO_2 displacement requirements in the EU's transport sectors.

However, in Appendix A, Rosager elaborates that while the unsubsidised biogas certificates rely on a market, the subsidy is guaranteed for 20 years, which provides more certainty. In addition, it is an option to select or deselect the subsidy on a monthly basis. Therefore, biogas plants could apply for the subsidy as a precautionary measure, in case the market price of unsubsidised biogas certificates should plunge. The subsidy may not be able to cover all of the costs, but it might be able to limit the loss.

7.3 E-methanol Market

In this section, the market conditions for e-methanol are investigated. Firstly, the global market demand and applications of e-methanol will be accounted for. Secondly, based on an analysis of e-methanol production costs and price points from the market, the current and future selling prices of e-methanol will be estimated.

7.3.1 Global Market Demand and Applications

As it appears from Figure 7.7, the global market demand for methanol is increasing along with the global production capacity. In 2019, the global market demand was 98 million tons. Originally, methanol was produced from wood, but during the 1920s and 1940s, production from respectively coal and natural gas began, which allowed a substantial upscaling of production capacity. In 2021, 65% of methanol is produced from natural gas, while 35% is produced from coal, and less than 1% is produced from biomass (biomethanol) or renewable energy (e-methanol). [IRENA and MI, 2021]

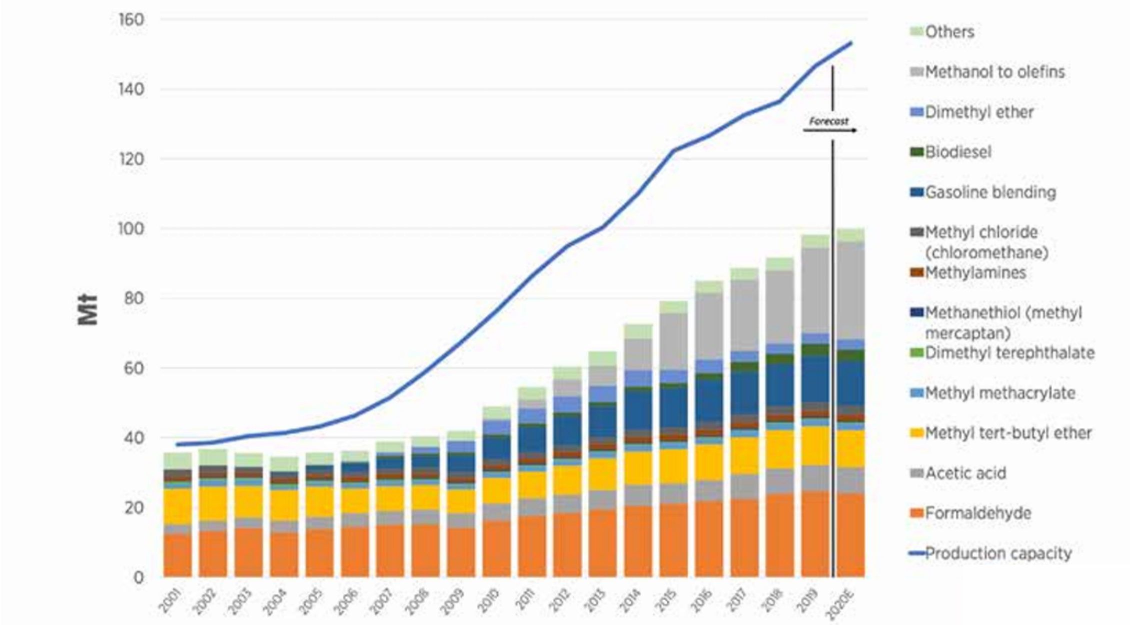

Figure 7.7. The global methanol demand from 2001-2019 [IRENA and MI, 2021]

Methanol is used in production of various chemicals, in production of fuels, or directly as a fuel. Around 31% of the global methanol demand is due to methanol being used as a fuel or for fuel production, and it is an increasing demand. This tendency especially applies to methanol used directly as a fuel, as this usage in 2000 was less than 1% of the global demand, and in 2021 it was more than 14%. [IRENA and MI, 2021]

Looking forward, the global demand is projected to be 120 million tons in 2025 and 500 million tons in 2050. This would require annual market growth rates of 3.4% (2019-2025) and 5.9% (2025-2050). As green methanol can directly substitute fossil methanol, the share of green methanol will increase to 77% towards 2050. In 2050, 50% of the methanol consumption is expected to be e-methanol, and 27% is expected to be biomethanol. [IRENA and MI, 2021]

So far, the demand for green methanol has mainly been from transport sectors due to sustainability requirements regarding the fuels. For instance in the EU, 14% of the energy used for transport must be renewable in 2030. While direct electrification is the preferred choice for most cars, green methanol is aimed at trucks and shipping. [IRENA and MI, 2021]

7.3.2 Production Costs and Pricing

The production cost of methanol predominantly depends on the cost of the raw material. Methanol production from natural gas costs around 100 $/ton in North America and the Middle East, while it costs 300 $/ton in Europe. Methanol production from coal is almost entirely restricted to China and costs between 150-250 $/ton. Figure 7.8 shows the price development of methanol on the European market from 1995-2020. It can be seen that when adjusting for inflation, the contract price has fluctuated between 200-400 $/ton. As the production cost of methanol in Europe is 300 \$/ton, it would suggest that the selling price is closely related to the cost of production. [IRENA and MI, 2021]

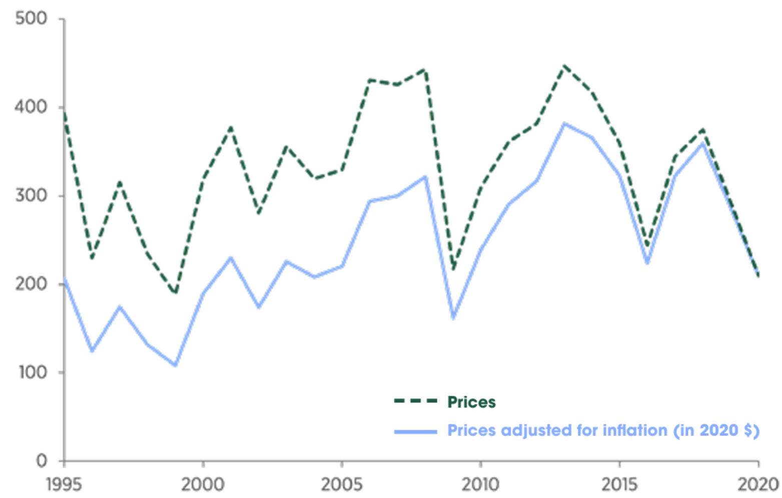

Figure 7.8. The average contract price of methanol in Europe from 1995-2020 [\$/ton] [IRENA and MI, 2021]

The production cost of e-methanol is, likewise, mainly dependant on the cost of electricity for hydrogen production and the cost of biogenic CO_2. It is also possible to achieve benefits from economics of scale by increasing the production capacity. Table 7.4 shows the production cost of e-methanol, and how it is expected to develop towards 2050. The table differentiates between production using CO_2 captured from point sources and production using CO_2 from Direct Air Capture (DAC). DAC is a more energy intensive process, which is thus linked with a higher cost. [IRENA and MI, 2021]

	2015-2018	**2030**	**2050**
Production with CO2 from Point Sources	820-1,620 \$/ton	410-750 \$/ton	250-630 \$/ton
Production with CO2 from DAC	1,220-2,380 \$/ton	600-1,070 \$/ton	290-630 \$/ton

Table 7.4. The future development in e-methanol production cost dependant on the CO2-source [IRENA and MI, 2021]

The selling price of e-methanol can be estimated using price points from the market. The price of e-methanol that is delivered from the Gulf Coast of the United States to Rotterdam is 2,429.80 \$/ton [Holmstad, 2023]. Likewise, Mærsk paid 2,500 \$/ton for biomethanol, when Laura Maersk had her maiden voyage from South Korea to Copenhagen in Denmark [Maritime Denmark, 2023]. Table 7.5 shows, how the selling price will develop towards 2050, if it is assumed to follow the same development as the cost of production. For this calculation, the production is assumed to use CO_2 from point sources.

	Current	**2030**	**2050**
Production Cost Range	820-1,620 $/ton	410-750 $/ton	250-630 $/ton
Production Cost Mean	1,220 $/ton	580 $/ton	440 $/ton
Selling Price Estimation	2,500 $/ton	1,190 $/ton	900 $/ton

Table 7.5. Estimation of the current and future selling price of e-methanol based on production costs and price points from the market

In Appendix B, Kristensen agrees that using specific price points from the market is a valid approach to determine a selling price of e-methanol. Furthermore, estimating future selling prices based on the development of the production cost is, likewise, a reasonable method for extrapolating the selling price. Kristensen adds that it provides transparency with the underlying assumptions.

Simulation Model 8

The aim of this chapter is to answer the third sub-question:

How can a simulation model be devised with the aim of making techno-economic analyses of carbon utilisation at biogas plants?

On the basis of the findings made in Chapter 6 and Chapter 7, a model has been developed in Excel to simulate and evaluate three scenarios. The scenarios are three different pathways to utilising CO_2 from biogas plants in Denmark. The scenarios are (1) liquefaction of CO_2, (2) production of e-methane, and (3) production of e-methanol. The general idea behind the model is that a certain amount of CO_2 or biogas is entered into the model, and the utilisation of the CO_2 is then simulated against the electricity market. This chapter aims at describing the model to provide transparency with the simulations and the assumptions behind the model.

To intelligibly describe the composition and the workings of the simulation model. The chapter has been divided into five sections. The sections are listed here with a brief description of their content.

- **8.1 Scenarios:** The three scenarios are described to provide an overview of the energy systems that are being modelled.
- **8.2 Technological Options:** All of the options that the model offers to choose the technological specifications are accounted for along with the reasoning behind them.
- **8.3 Electricity Market:** The electricity price distributions that are available in the model are described along with the transmission tariff and the distribution tariff.
- **8.4 Intermediate Storage:** It is explained, how the capacity and the cost of the intermediate storage is determined.
- **8.5 Water and By-products:** The price of water and the cost of waste water is investigated, and the point of view with regard to income from selling excess heat and oxygen is accounted for.

8.1 Scenarios

In this section, the three scenarios that the model simulates are described. The aim of this section is to provide a visual and explanatory overview of the energy systems that are being modelled.

8.1.1 Liquefaction Scenario

In the first scenario, the CO_2 is liquefied and sold as liquid CO_2. The energy system that is modelled to simulate the liquefaction of CO_2 is visualised on Figure 8.1.

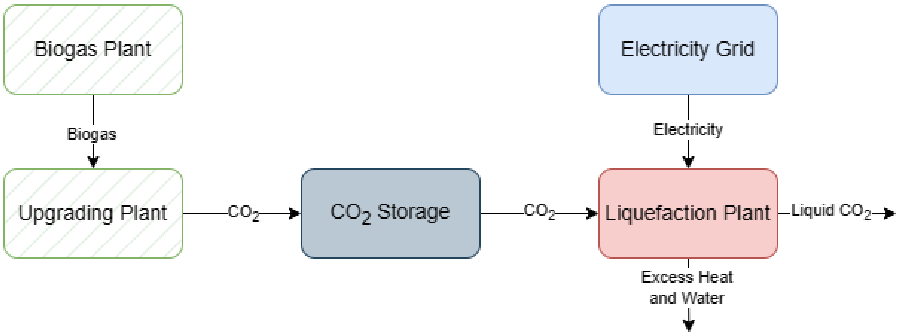

Figure 8.1. Visualisation of the energy system for liquefaction of CO_2

The biogas plant itself and the upgrading plant are not simulated in the model, which is why, the boxes are hatched on the figure. Only the flow of CO_2 into the CO_2 storage is included in the model. An intermediate CO_2 storage is required, as the CO_2 flow is assumed to be constant, while the liquefaction plant at most can reach 8,308 full load hours. The CO_2 storage also provides the option of flexible operation to benefit from fluctuating electricity prices. The electricity to operate the liquefaction plant is supplied by the electricity grid and, other than liquefied CO_2, the plant produces excess heat and waste water.

8.1.2 E-methane Scenario

In the second scenario, the CO_2 is used for production of e-methane. The energy system that is modelled to simulate the production of e-methane is visualised on Figure 8.2.

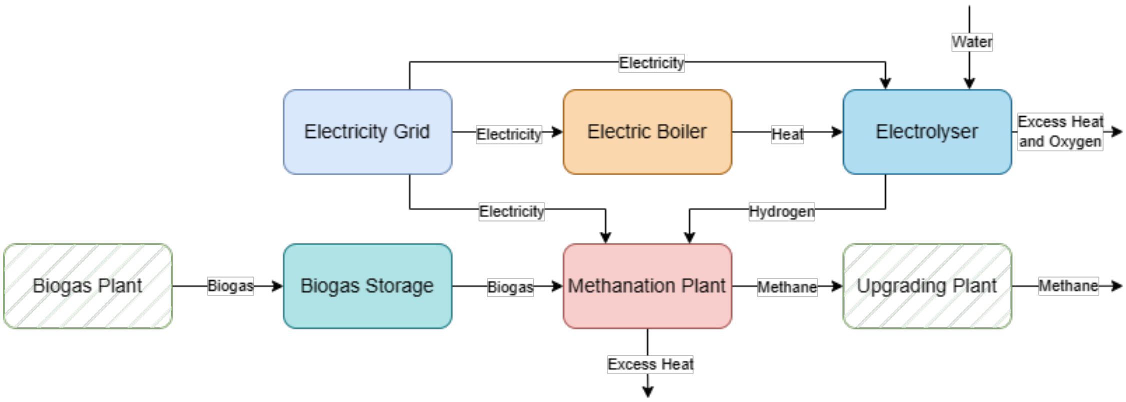

Figure 8.2. Visualisation of the energy system for production of e-methane

As stated in Section 6.2, the methanation plant will be ex-situ and upstream from the upgrading plant. This entails that the intermediate storage will be a biogas storage, and the methanation plant will be supplied with biogas instead of CO_2. The electricity grid will supply the electrolyser, the methanation plant, and the electric boiler with electricity. The electric boiler is only included in the simulation, in case the electrolyser is SOEC, which requires heat to operate. If the electrolyser is AEC or PEMEC, there is no electric boiler. The electric boiler has been chosen over a high temperature heat pump, as the electric boiler has a lower CAPEX, can reach higher temperatures, and has a greater regulation ability in terms of having a flexible operation [DEA, 2022]. The electrolyser supplies the methanation plant with hydrogen, and both the methanation plant and the electrolyser produces excess heat. Oxygen is also a by-product from the electrolyser, and apart from electricity (and heat), the electrolyser consumes water. The biogas is thus converted into biomethane and e-methane. However, it is only the income from selling e-methane that is included in the economic evaluation. The income from selling biomethane is disregarded, as it also is in the other scenarios.

8.1.3 E-methanol Scenario

In the third scenario, the CO_2 is used for production of e-methanol. The energy system that is modelled to simulate the production of e-methanol is visualised on Figure 8.3.

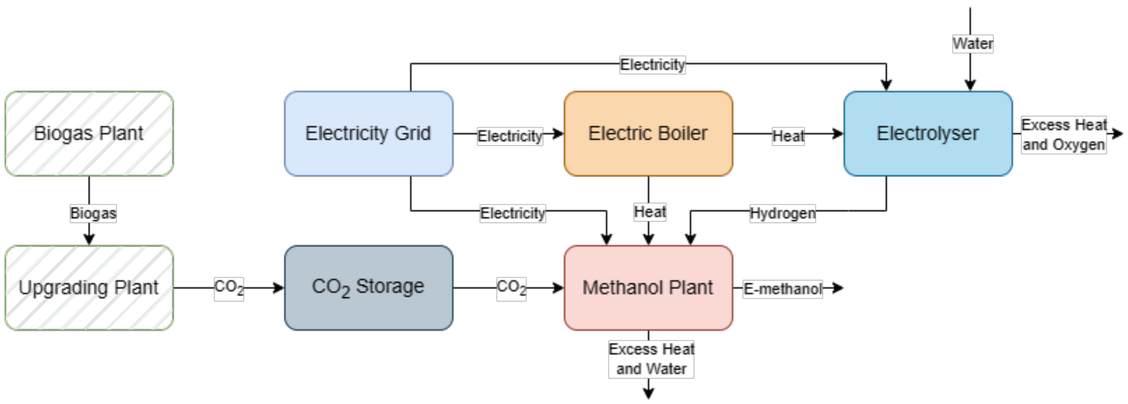

Figure 8.3. Visualisation of the energy system for production of e-methanol

The e-methanol scenario is much similar to the e-methane scenario. However, other than the product being e-methanol instead of e-methane, there are some additional differences. The methanol plant is supplied with CO_2 from an intermediate storage, the methanol plant produces waste water, and the methanol plant requires heat, which is delivered by the electric boiler.

8.2 Technological Options

The scenarios make use of various technologies to utilise the CO_2. The technical and financial specifications for those technologies are attached as Appendix C. In this section, the different technological options and the reasoning behind the choices are described. Figure 8.4 provides an overview of all of the options that are available in the simulation model when choosing the technological specifications. As Figure 8.4 shows, the options vary across the three scenarios.

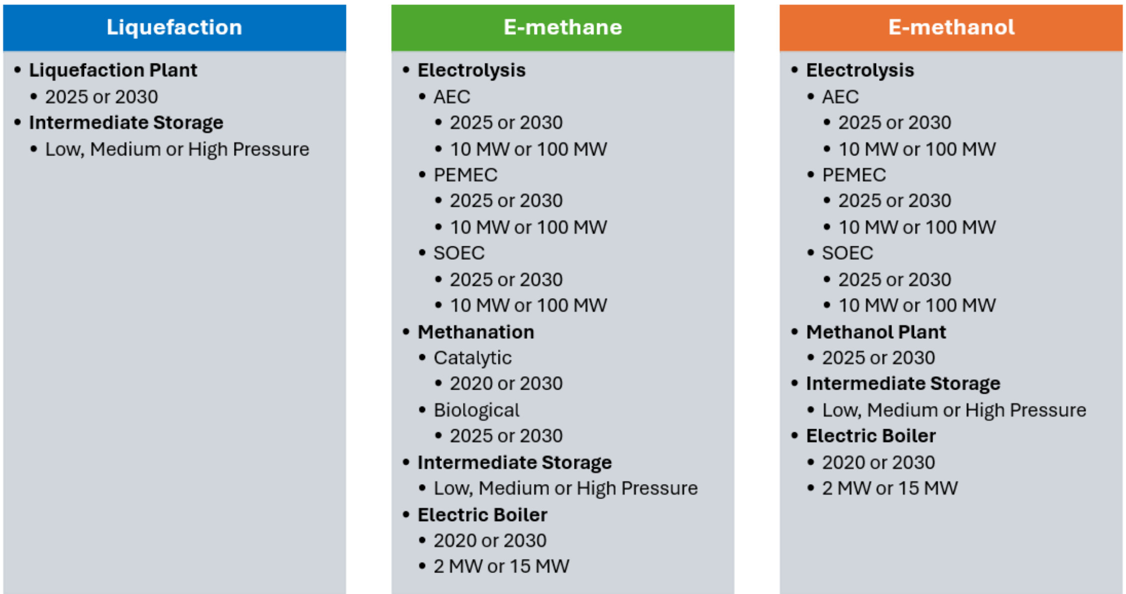

Figure 8.4. The technological options in the three scenarios

As technologies tend to develop through time, the specifications are dependent on the year of the investment. Therefore, the preferred year needs to be specified for every technology in the model. For most of the technologies, the choice is between 2025 or 2030. However, for the electric boiler and catalytic methanation, 2025 data was not available, so 2020 data was collected instead. The intermediate storage is the only technology, where the year can not be specified.

Likewise, as benefits from economics of scale can be obtained, the financial specifications for the electrolysers and the electric boiler varies with the capacity. Therefore, the capacity that best resembles the simulated capacity must be specified. For the electrolysers the choice is between 10 MW and 100 MW, while the choice is between 2 MW and 15 MW for the electric boiler. Similarly, the financial specifications for the intermediate storage depend on the pressure. Therefore, it must be specified in the simulation, weather it is low pressure, medium pressure, or high pressure.

8.3 Electricity Market

In this section, the electricity price distributions of 2040, 2030, 2023, 2022 and 2021 will be presented and compared. The pros and cons of using historical and projected price distributions will be discussed. In addition to the electricity price distributions, the simulation model features the transmission tariff and the distribution tariff, which will also be described.

8.3.1 Electricity Price Distributions

The model simulates operation against the electricity market on an hourly basis over a year. Therefore, the model requires an electricity price distribution, which is the electricity spot price for every hour of a year. Electricity price distributions can be either historical price distributions from past years or projected price distributions for future years.

Using historical or projected price distributions have its advantages and disadvantages. The pro of using historical price distributions is that they are realistic, as they show actual spot prices. However, the con is that they do not consider the future development of supply and demand. On the contrary, the pro of using projected price distributions is that they take the future development into account, but the con is that they tend to be more homogeneous with disproportionately many repetitions of the exact same spot price during different hours. This tendency is because, they are based on assumptions and estimations instead of actual spot prices.

In this model, the historical price distributions from 2021, 2022 and 2023 are available along with the projected price distributions for 2030 and 2040. This enables the model to simulate with five different price distributions and test, how it affects the results. The historical electricity price distributions have been collected from Energi Data Service [Energinet, 2024d]. The projected electricity price distributions are from the Danish Energy Agency's analysis prerequisites for 2022, which were prepared for Energinet [DEA, 2023d].

As mentioned before, the issue with projected electricity price distributions is that the exact same spot price occurs during disproportionately many hours. Figure 8.5 proves this point by showing two histograms of the spot prices from the projected price distributions for 2030 and 2040. Both histograms show a skewed frequency of spot prices. In 2030, the spot price is between 55-56 €/MWh during almost 800 hours, while a spot price between 56-57 €/MWh is not even occurring once. In 2040, the same pattern can be observed, where the spot price is between 43-44 €/MWh during 830 hours, while the spot price is never between 44-45 €/MWh. Then again, the spot price is between 45-46 €/MWh during more than 700 hours.

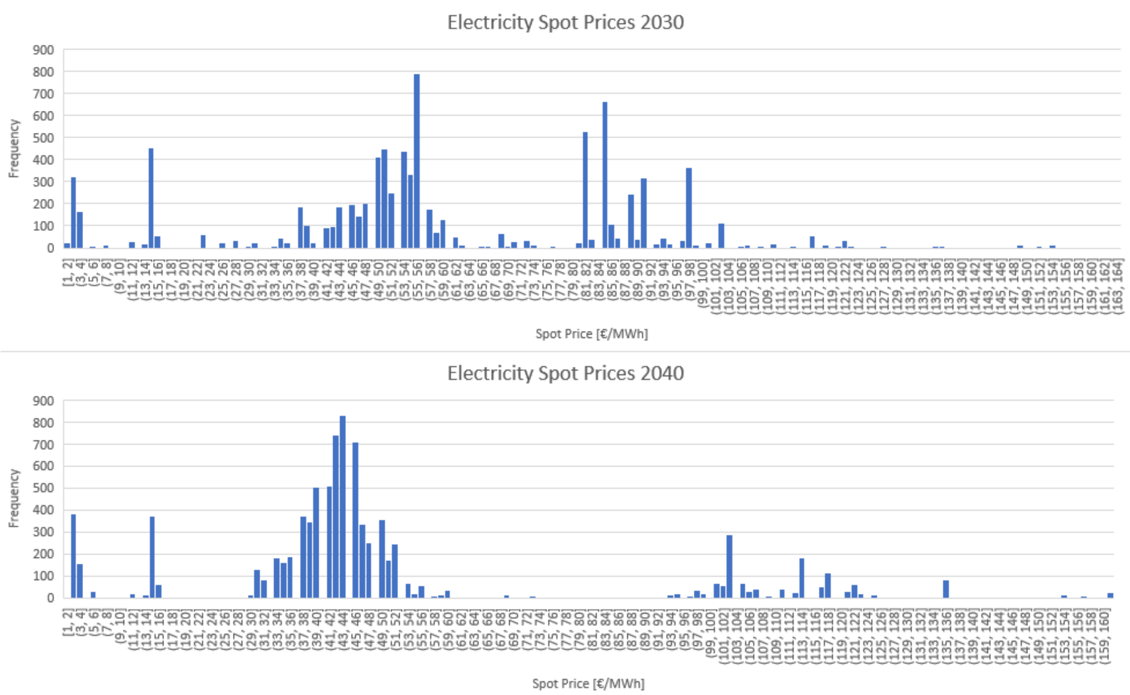

Figure 8.5. Histograms of the projected electricity spot prices in 2030 and 2040 [DEA, 2023d]

Figure 8.5 show that there is a repetition and thus an overrepresentation of certain spot prices, while other spot prices does not appear at all. However, the RAND function in Excel can rectify this shortcoming. By using the RAND function, all of the spot prices in the projected price distributions are changed by a random number in a positive or negative direction by maximum 5 €/MWh. This ensures that the exact same spot price is unlikely to be repeated. Figure 8.6 shows the result of the randomisation.

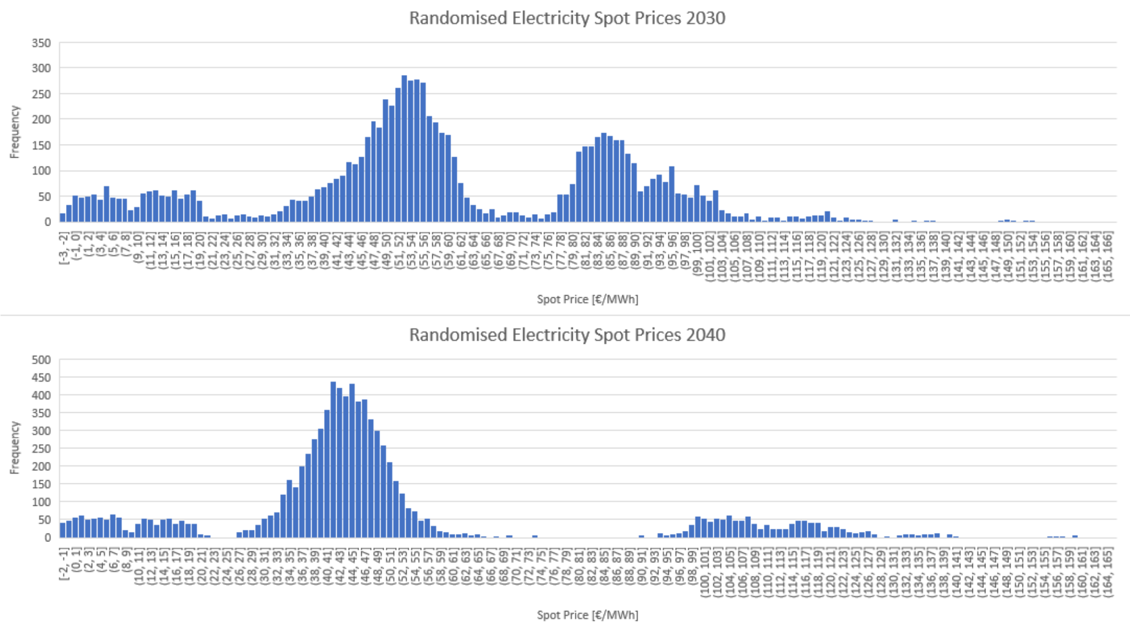

Figure 8.6. Randomised histograms of the projected electricity spot prices in 2030 and 2040 [DEA, 2023d]

The price distributions can be compared by duration curves, which Figure 8.7 shows. A duration curve shows the spot prices of a price distribution, where the spot prices are sorted from lowest to highest. It can be seen that the spot prices in 2022 are generally higher compared to the other years. It can also be seen that even though the spot prices in 2023 and 2021 are similar on average, 2021 have higher peaks than 2023. The projected spot prices for 2030 and 2040 are significantly lower with relatively low peaks compared to the other years.

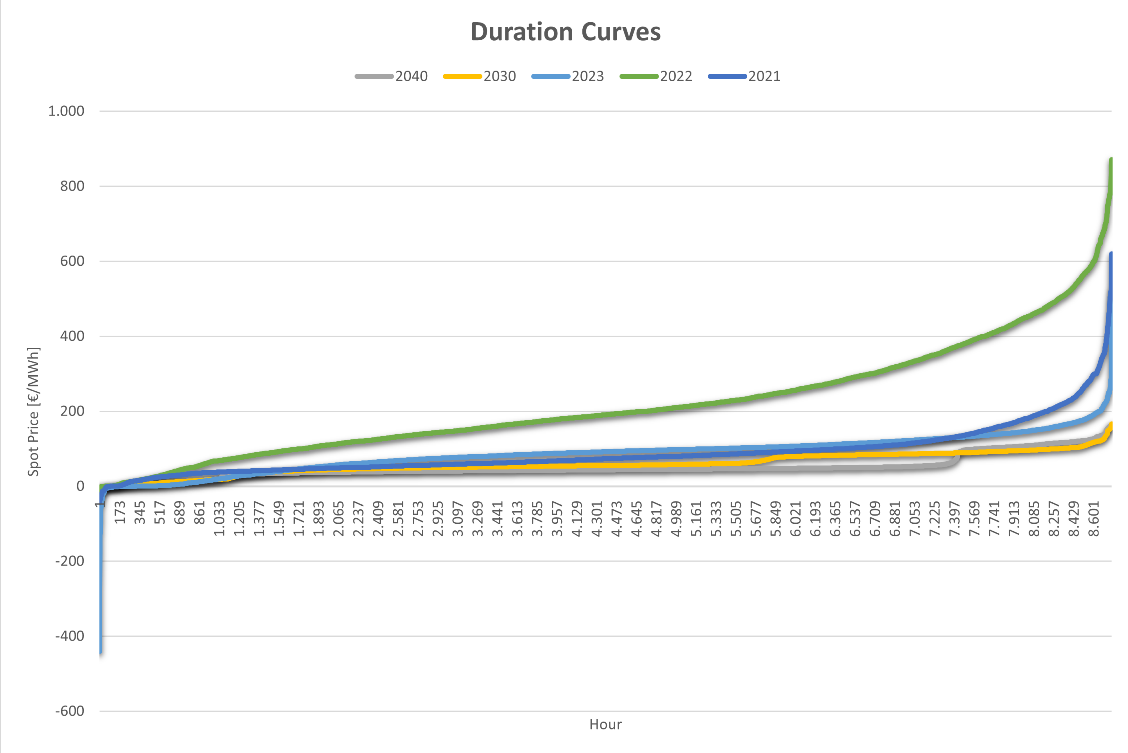

Figure 8.7. Comparison of price distributions by duration curves [Energinet, 2024d] [DEA, 2023d]

The price distributions can also be compared by box plots, which Figure 8.8 shows. The X's in the box plots mark the average spot prices. The box plots highlight that the spot prices in 2030 are more fluctuating than in 2040. However, the projected spot prices are generally lower and less volatile than the historical spot prices.

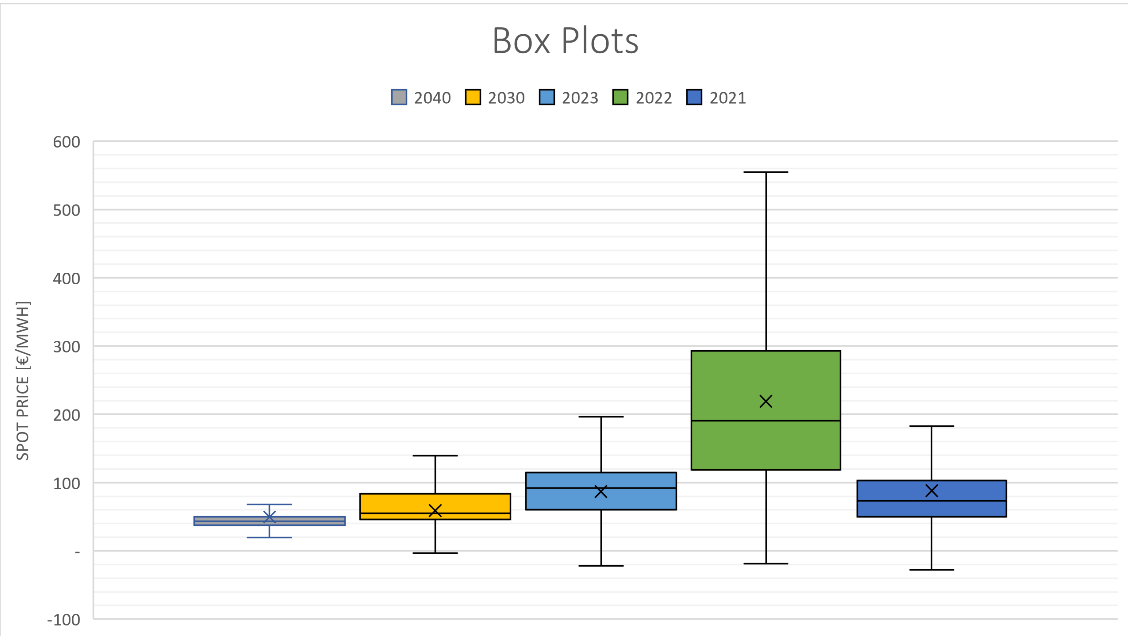

Figure 8.8. Comparison of price distributions by box plots [Energinet, 2024d] [DEA, 2023d]

8.3.2 Electricity Tariffs

The electricity grid is composed of a transmission grid and distribution grids. The transmission grid is operated by Energinet, which is the Danish Transmission System Operator (TSO). When using the transmission grid Energinet collects two tariffs. The grid tariff of 9.93 €/MWh covers investments in new grid capacity and maintenance of the existing transmission grid. The system tariff of 6.84 €/MWh covers the expenses for ancillary services and ensuring security of supply. If a consumer offtakes more than 100 GWh/year, the system tariff is reduced to 0.68 €/MWh for the share of the consumption that exceeds 100 GWh/year. [Energinet, 2024f]

The grid tariff, the system tariff, and the discount for a consumption over 100 GWh/year are included in the simulation model. This means that the total transmission tariff is 16.77 €/MWh, until the electricity consumption exceeds 100 GWh/year. Once the electricity consumption exceeds 100 GWh/year, the transmission tariff is reduced to 10.61 €/MWh for the remainder of the consumption.

The distribution grids are operated by Distribution System Operators (DSO), who collect distribution tariffs. The distribution tariffs differ from DSO to DSO, however, it is not possible to freely choose a DSO. The DSO is assigned based on the geographical location of the grid connection. The DSO that covers most of Jutland is Elnetselskabet N1. Elnetselskabet N1's distribution tariff depend on, which customer category the consumer belongs to. The appropriate customer category is determined by the voltage level at the grid connection. [Elnetselskabet N1, 2024a]

The model assumes the customer category of A-Low to be the appropriate customer category, as this customer category provides a realistic distribution tariff in proportion to the electricity spot price and the transmission tariff. The distribution tariff changes between base load (2.10 €/MWh), high load (6.33 €/MWh), and peak load (12.65 €/MWh). The changes are made on a daily basis and depend on, weather it is a weekday or a weekend, and weather it is during the summer half-year or the winter half-year. Table 8.1 shows, how the distribution tariff changes for a A-Low customer. The idea behind a changing distribution tariff is that it creates an incentive to even out the consumption pattern, so that the existing grid capacity is efficiently utilised, and the need for additional grid capacity is reduced. [Elnetselskabet N1, 2024b]

	Summer (April to September)		**Winter (October to March)**	
Time of Day	**Weekday Tariff**	**Weekend Tariff**	**Weekday Tariff**	**Weekend Tariff**
00.00-06.00	2.10 €/MWh	2.10 €/MWh	2.10 €/MWh	2.10 €/MWh
06.00-21.00	6.33 €/MWh	2.10 €/MWh	12.65 €/MWh	6.33 €/MWh
21.00-24.00	6.33 €/MWh	2.10 €/MWh	6.33 €/MWh	6.33 €/MWh

Table 8.1. The distribution tariff as an A-Low customer at Netselskabet N1 [Elnetselskabet N1, 2024b]

The distribution tariff is incorporated into the model, so that it changes in accordance with Table 8.1. The distribution tariff is 4.37 €/MWh on average during the summer half-year, while it increases to 8.10 €/MWh during the winter half-year. However, these averages only apply, if the consumption pattern is completely level. A flexible consumption pattern can reduce the average cost of the distribution tariff.

8.4 Intermediate Storage

To have a flexible production and simultaneously utilise all of the available feedstock, an intermediate storage of CO_2 or biogas is required. This section will cover, how the simulation model determines the capacity of the storage, and how the cost is estimated.

The capacity of the storage depends on the number of full load hours and the hourly inflow of CO_2 (ton/hour) or biogas (Nm^3/hour). The storage should be able to contain the feedstock, if all of the full load hours are in the end of the year. Conversely, the storage should also have enough feedstock to supply the operation, if all of the full load hours are in the beginning of the year. Therefore, the capacity of the storage is determined by the following formula, where FLH is an abbreviation for Full Load Hours.

$$(8,760 - FLH) * Inflow * 2 = Capacity$$

In the beginning and in the end of the year, the storage is always half-full. Figure 8.9 shows an example of, how the CO_2 storage is simulated in the e-methanol scenario with the electricity price distribution for 2030. In this example, the e-methanol plant has 8,089 full load hours and the CO_2 inflow is 2.28 ton/hour (20,000 ton/year). Therefore, the capacity of the storage is determined to be 3,064 ton.

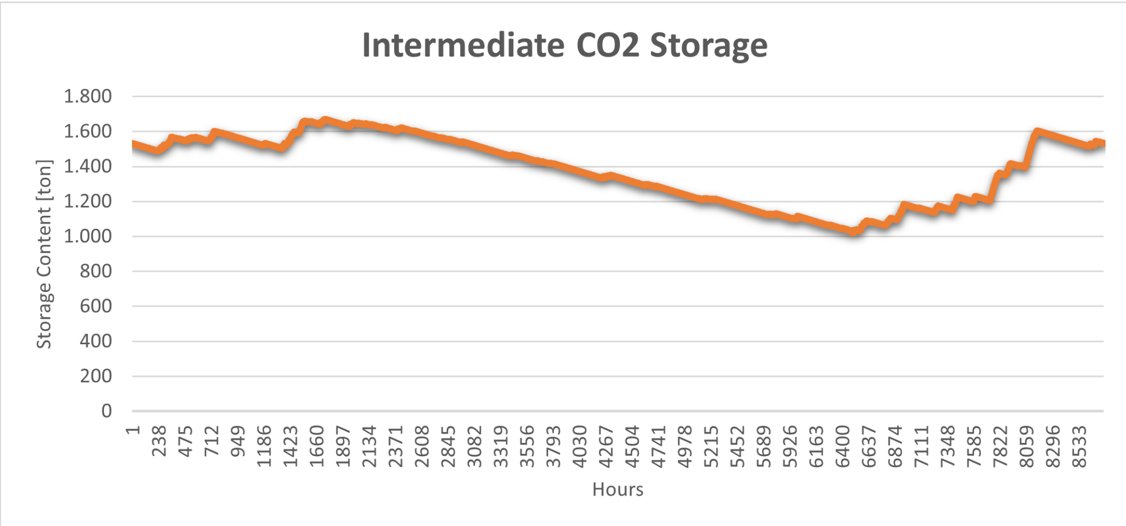

Figure 8.9. Simulation of the intermediate CO_2 storage in the e-methanol scenario

It appears from Figure 8.9 that due to the electricity price distribution, the full load hours are grouped together halfway through the year, which causes the storage content to decrease. In this example, the outflow during operation is 2.47 ton/hour, so the storage content decreases by 0.19 ton/hour, when the plant is in operation. However, the storage refills to half-full towards the end of the year, as the electricity price increase.

The Technology Catalogues published by the Danish Energy Agency (DEA) only have data on an intermediate CO_2 storage tank following liquefaction. As the storage tank is meant for liquefied CO_2, the CAPEX is thus much higher (3,800 €/ton), than it would be for a tank containing gaseous CO_2. However, the technical lifetime of 25 years is useful. The Technology Catalogues does not have data on a biogas storage either. [DEA, 2023c]

In the liquefaction scenario and the e-methanol scenario, the intermediate storage contains CO_2. In a literature study, it is found that the cost of CO_2 storage in intermediate storage tanks increases concurrently with the pressure. Therefore, the simulation model allows the choice between low pressure (5.5-9.8 bar), medium pressure (14-20 bar), and high pressure (45-72 bar). As the cost of a low pressure tank is significantly lower than a medium pressure tank and especially a high pressure tank, it is most likely that a low pressure tank will be the preferred option. The specific CAPEX and OPEX of the CO_2 storage can be found in Appendix C. The annual OPEX is assumed to be 5% of the CAPEX. [Durusut og Joos, 2018]

In the e-methane scenario, the intermediate storage contains biogas. With a CO_2 density of 1.97 kg/Nm^3, the cost of the CO_2 storage is converted from €/ton to €/Nm^3 and applied as an estimate of the cost for a biogas storage. The specific CAPEX and OPEX of the biogas storage can be found in Appendix C. Once again, the annual OPEX is assumed to be 5% of the CAPEX. [Durusut og Joos, 2018]

8.5 Water and By-products

In this section, the price of water and the cost of producing waste waster are determined. It is also explained, why the model does not include any income from selling excess heat or oxygen.

The electrolysers require water as input, and the liquefaction plant and the methanol plant produce waste water as a output. In 2022, the average price of drinking water in Denmark was 2.67 €/m^3 (including a tax of 0.85 €/m^3), and the average cost of waste water was 5.32 €/m^3 (including a tax of 0.07 €/m^3). By law, there is a discount scheme for large-scale producers of waste water. A 20% discount is obtained, if production is between 500-20,000 m^3/year, and a 60% discount is obtained, if production exceeds 20,000 m^3/year. [DANVA, 2024]

The price of drinking water (2.67 €/m^3) and the cost of waste water (5.32 €/m^3) are added to the simulation model. The model also takes the discount scheme for waste water into account, so that the appropriate discount is obtained, when the production qualifies for it.

The electrolysers (except SOEC), the methanation plant, and the methanol plant produces excess heat. It would normally be investigated, weather the excess heat could be sold to the local utility company for district heating. However, as most biogas plants are located in rural areas, it will be difficult to utilise the excess heat as district heating. The excess heat may be useful for other processes at the biogas plant and could potentially reduce the cost of heating elsewhere, but that is outside the scope of this analysis. Therefore, there is no income from selling excess heat in the simulation model.

Even though, the electrolysers produce oxygen, which is a commodity that can be sold, the simulation model does not factor in any income from selling oxygen. The reason is that hydrogen production by means of electrolysis is becoming more prevalent, and the increasing production of oxygen is likely to saturate the market. Therefore, the potential income from selling oxygen should not be counted on, as it is uncertain, weather it will be possible to sell.

Results 9

The aim of this chapter is to answer the fourth sub-question:

What are the technical and economic results of utilising the carbon?

The sub-question will be answered by evaluating the three scenarios using the simulation model that is described in Chapter 8. The scenarios are (1) liquefaction of CO_2, (2) production of e-methane, (3) production of e-methanol. Firstly, the simulation conditions will be specified. With these simulation conditions, each scenario will be technically and economically evaluated. Additionally, simulations will be made with alternative conditions to test the robustness of the scenarios and explore other simulation options. Finally, the results will be summarised in a table, and the key findings will be listed.

9.1 Simulation Conditions

Before analysing the results, the conditions of the simulation has to be specified. This section accounts for these conditions, which encompass the choice of electricity price distribution, the available amount of feedstock (CO_2 and biogas), technology specifications, and selling prices. The conditions specified in this section will also be subject to changes in the sensitivity studies.

9.1.1 Technical Conditions

As the evaluation period is from 2025-2045, the electricity price distribution for 2030 will be chosen. The electricity price distributions of 2040, 2023, 2022 and 2021 will, however, be included in the analysis in Section 9.5.

In the liquefaction scenario and the e-methanol scenario, 20,000 ton CO_2 will be available. This corresponds to 25 million Nm^3 biogas, which will be available in the e-methane scenario. The conversion between CO_2 and biogas relies on the assumption that biogas volumetrically consists of 40% CO_2 and 60% methane. Based on the upgrading capacity and a capacity factor of 80%, it is estimated that around one third of the Danish biogas plants with a grid connection will have this amount of feedstock available [Biogas Danmark, 2022].

As the investment is made in 2025, the technology data for 2025 will be used, where it is possible. 2025 data is not available for the catalytic methanation and the electric boiler, so with a conservative approach 2020 data will be used instead for these two technologies.

In all three scenarios, a low pressure intermediate storage of CO_2 or biogas will be chosen, as this is more cost-effective than medium and high pressure.

The choice of electrolysis technology is based on the analysis in Section 6.4. AEC is the most mature electrolysis technology, and will therefore be used in the e-methane and the e-methanol scenarios. Furthermore, AEC allows the water to be less pure than PEMEC, and the energy efficiency is higher compared to PEMEC. Even though, the raw materials for AEC are more expensive and scarce than SOEC, they are cheaper and more abundant than the raw materials used for PEMEC. SOEC is, however, the least mature electrolysis technology.

In section 6.2, catalytic and biological methanation is compared. Catalytic methanation is a mature technology, while biological methanation has only been demonstrated on small scale. Therefore, catalytic methanation will be chosen in this instance.

9.1.2 Selling Prices

The selling prices of liquid CO_2 is investigated in Section 7.1. According to Agriportance's market price estimates, the selling price of liquid CO_2 is around 40 €/ton across Germany. However, according to Anders Søgaard Kristensen, who is a manager at Rambøll Management Consulting, this seems to be a low price, as he has encountered prices of 55-85 €/ton. Especially due to the emerging markets for CO_2, the global demand for biogenic CO_2 is expected to increase dramatically. It can be assumed that as the demand for biogenic CO_2 increases, the price will follow. Therefore, a selling price of 65 €/ton is assumed.

In Section 7.2, it is described, how the selling price of e-methane is the combination of the spot market price for gas and the price of the biogas certificate. In recent years, the spot price has been extremely fluctuating, however, Kristensen expects it to stabilise around 25-30 €/MWh. According to Frank Rosager, who is the CEO of Biogas Danmark, the biogas certificates for e-methane will approximately be worth the same as biogas certificates for biomethane from manure. The price of those biogas certificates have dropped recently due to a Chinese disruption of the market. If the recent price drop is disregarded, a reasonable price would be 250 €/MWh. Therefore, a gas spot price of 30 €/MWh will be assumed along with a biogas certificate price of 250 €/MWh. This results in a combined e-methane selling price of 280 €/MWh. The subsidy for e-methane will not be added to the selling price, as unsubsidised biogas certificates are worth more than the combined value of subsidised biogas certificates plus the subsidy.

In Section 7.3, it was discovered that the selling price of methanol is closely related to the cost of production. According to price points from the market, the current selling price of green methanol is 2,500 €/ton. If the selling price follows the same pattern of development as the cost of production, the selling price will be 1,190 €/ton in 2030 and 900 €/ton in 2050. Assuming a linear price development from 2025 to 2030 and from 2030 to 2050, the average selling price during the evaluation period (2025-2045) will be 1,294 €/ton. Therefore, a selling price of 1,300 €/ton is assumed.

9.2 Liquefaction Scenario

In this scenario, 20,000 ton CO_2 is liquefied annually and sold at 65 €/ton. This requires an intermediate CO_2 storage and a liquefaction plant.

9.2.1 Technical Evaluation

The liquefaction plant produces 20,000 ton liquefied CO_2 annually. Due to the stable electricity prices in 2030 and the high cost of increasing the capacity, it is economically most beneficial for the plant to be operating as much as possible with a low capacity. Operation is, however, limited by the liquefaction plant that at most only can reach 8,308 full load hours. This entails a kip price of 125.47 €/MWh.

The capacity of the liquefaction plant is then 2.41 ton/hour, and the intermediate storage can hold 2,100 ton. At the lowest point throughout the year, the content of the intermediate storage is down to 588 ton. On an annual basis, 2,700 MWh electricity is consumed, and 6,900 MWh excess heat is produced along with 348 ton waste water.

9.2.2 Economic Evaluation

The initial investment is 4.45 million €, and the annual expenses afterwards are 394,000 €/year. The scrap value in 2045 is 249,000 €. Figure 9.1 shows, how the discounted costs are distributed throughout the evaluation period. It can be seen that the costs of the liquefaction plant constitute half of the total costs. The cost of electricity covers 28%, while the intermediate storage covers 22%. On average, electricity is purchased at 78.89 €/MWh including tariffs.

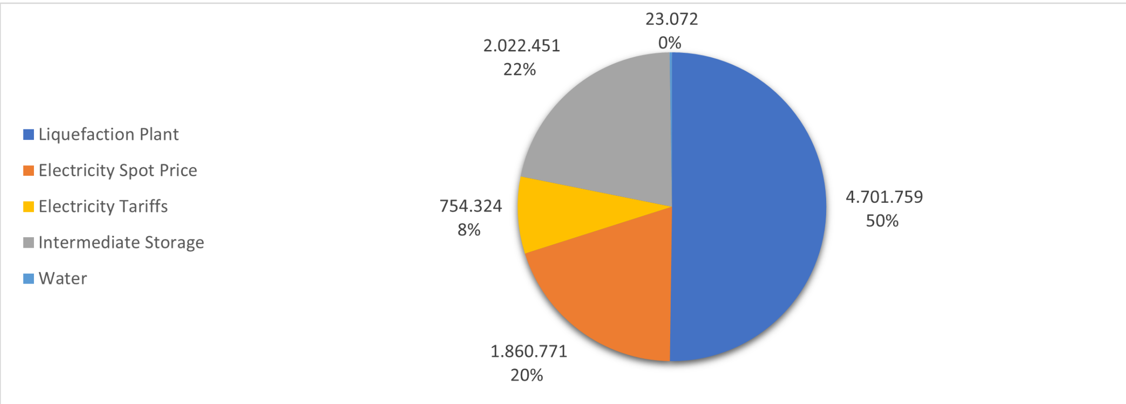

Figure 9.1. The discounted cost distribution in the liquefaction scenario [€]

The levelized cost of production is 37.19 €/ton and with a selling price of 65 €/ton, the Net Present Value (NPV) is 6.93 million €. The Real Rate of Return (RRoR) is 74%, which means that for every euro that is invested in this project, a profit of 0.74 € is earned.

Figure 9.2 shows, the sensitivity of the NPV to changes in the discount rate, the electricity cost, and the selling price. In the top, the discount rate is changed by ±3 percentage points from 5% to 2% and 8%. In the middle, the electricity cost is changed by ±25% from 78.89

€/MWh to 59.17 €/MWh and 98.61 €/MWh. In the bottom, the selling price is changed by ±25% from 65 €/ton to 48.75 €/ton and 81.25 €/ton.

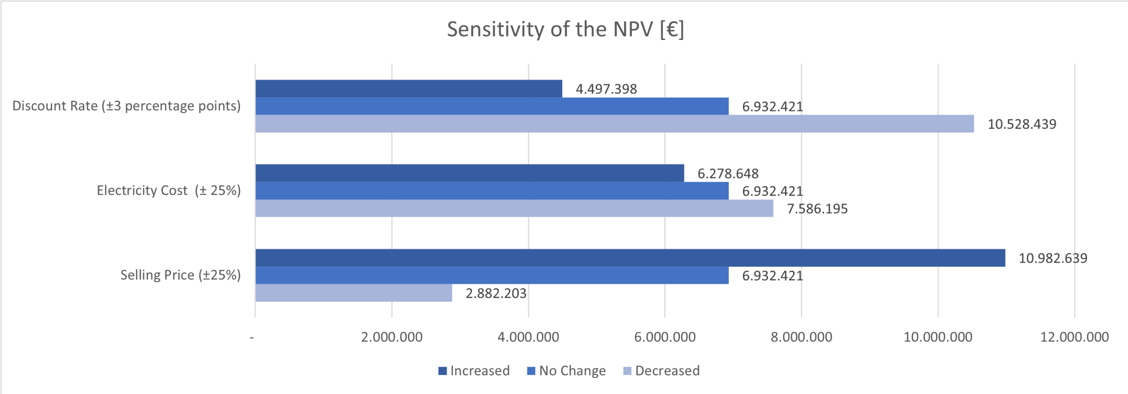

Figure 9.2. Sensitivity of the NPV in the liquefaction scenario

It appears that the NPV remains positive despite the aforementioned changes. The electricity cost only make up 28% of the total cost, while the selling price constitutes all of the income (except the scrap values). Therefore, the NPV is much more sensitive to changes in the selling price, than it is to changes in the electricity cost.

9.3 E-methane Scenario

In this scenario, 25 million Nm^3 biogas is converted into 148,000 MWh biomethane and 101,000 MWh e-methane annually. The conversion is accomplished by an intermediate biogas storage, a catalytic methanation plant, and an AEC electrolyser. The e-methane is sold at 280 €/MWh.

9.3.1 Technical Evaluation

The optimal kip price is determined to be 143 €/MWh, however, this would require 8,617 full load hours, and the catalytic methanation plant has a maximum number of full load hours of 8,396. Limited by the maximum number of full load hours, the kip price is instead 124.50 €/MWh.

The capacity of the intermediate biogas storage is 2.08 million Nm^3, and at its lowest point, the storage holds 0.53 million Nm^3. The catalytic methanation plant has a capacity of 29.65 MW methane. On an annual basis, 148,000 MWh biogas is supplied to the methanation plant along with 129,000 MWh hydrogen and 2,800 MWh electricity. These inputs result in a methane production of 249,000 MWh methane, of which 101,000 MWh is e-methane, and the rest is biomethane. Production is thus boosted by 40% compared to a scenario without production of e-methane.

The AEC electrolyser has a capacity of 26.11 MW and consumes 219,000 MWh electricity and 38,000 ton water annually. Combined the methanation plant and the electrolyser produces 86,000 MWh excess heat annually and roughly 2/3 is from the electrolyser. As the electrolyser is AEC and not SOEC, there is no need for an electric boiler in this simulation.

9.3.2 Economic Evaluation

The initial investment is 67.5 million €, and it is mostly split evenly between the electrolyser and the methanation plant, though the electrolyser is the more expensive of the two. The annual expenses are 20.9 million €, which can mainly be attributed to the cost of electricity. In 2045, the scrap value is 13.5 million €.

Figure 9.3 shows the discounted cost distribution during the evaluation period. As expected, the electricity spot price and electricity tariffs constitute the majority of the costs (64%). However, as the electricity prices in 2030 are relatively stable, it would reduce the NPV to have a higher capacity with fewer full load hours. The average cost of electricity is 76 €/MWh. It is almost 3 €/MWh cheaper than in the liquefaction scenario, despite the methanation scenario having more full load hours. The explanation is that the total electricity consumption is more than 100,000 MWh/year, which reduces the average system tariff due to the discount for large-scale consumers.

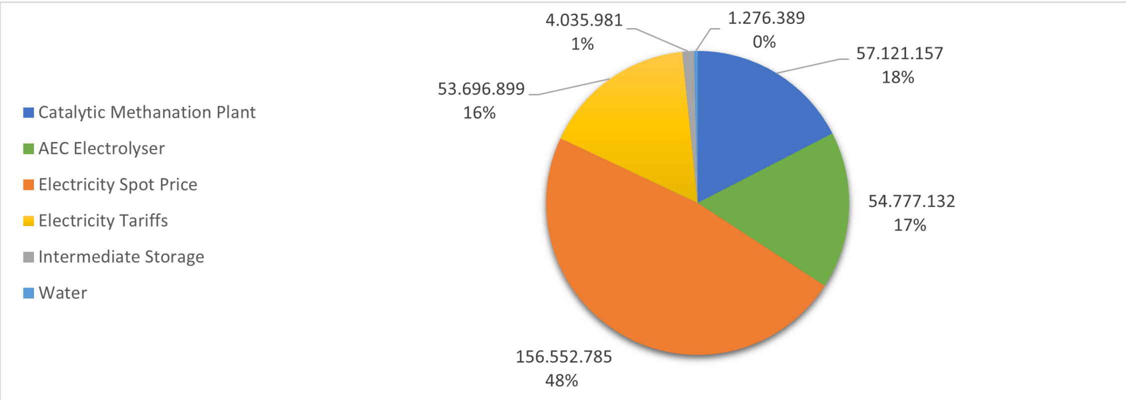

Figure 9.3. The discounted cost distribution in the e-methane scenario [€]

The levelized cost of production is 256.89 €/MWh e-methane and with a selling price of 280 €/MWh, the NPV is 29 million €. The RRoR is 9%, so despite having a higher NPV than the liquefaction scenario, the profit per invested euro is much lower.

Figure 9.4 shows, the sensitivity of the NPV to changes in the discount rate and the selling price. In the top, the discount rate is changed by ±3 percentage points from 5% to 2% and 8%. In the middle, the electricity cost is changed by ±25% from 76 €/MWh to 57 €/MWh and 95 €/MWh. In the bottom, the selling price is changed by ±25% from 280 €/MWh to 210 €/MWh and 350 €/MWh.

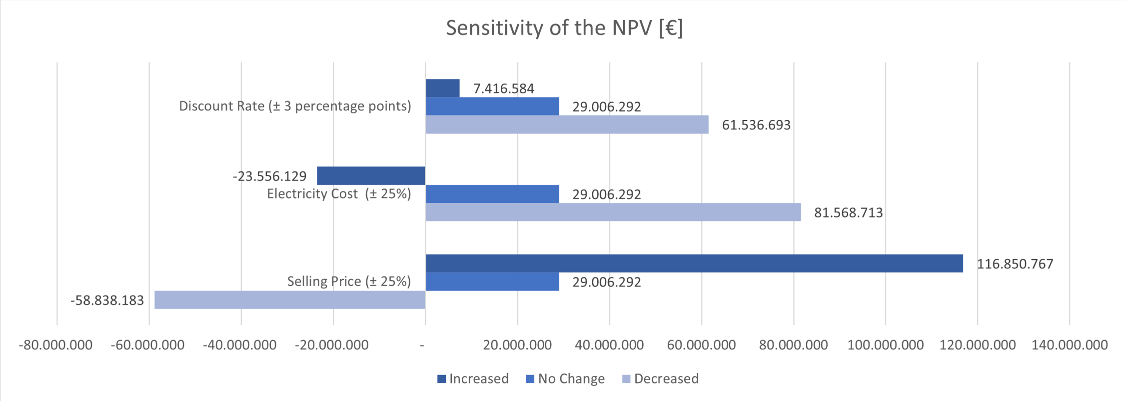

Figure 9.4. Sensitivity of the NPV in the e-methane scenario

It appears that the NPV will become negative, if the electricity cost is increased by 25%, or the selling price is decreased by 25%. In this scenario, the electricity cost constitutes 64% of the total cost, and thus the NPV is more sensitive to changes in the electricity cost, than it is in the liquefaction scenario.

9.4 E-methanol Scenario

In this scenario, 20,000 ton CO_2 is converted into 14,300 ton e-methanol annually. This is accomplished by an intermediate CO_2 storage, a methanol plant, an electric boiler, and an AEC electrolyser. The e-methanol is sold at 1,300 €/ton.

9.4.1 Technical Evaluation

In the e-methanol scenario the optimised kip price is 118.60 €/MWh, which results in 8.097 full load hours. As opposed to the other two scenarios, the optimal operation of the e-methanol plant is in this case not limited by the maximum number of full load hours. It would simply not improve the NPV to increase the number of full load hours and decrease the capacity. Likewise, it would neither improve the NPV to decrease the number of full load hours and increase the capacity. Figure 9.5 shows a duration curve with the kip price of 118.60 €/MWh against the simulated electricity prices in 2030.

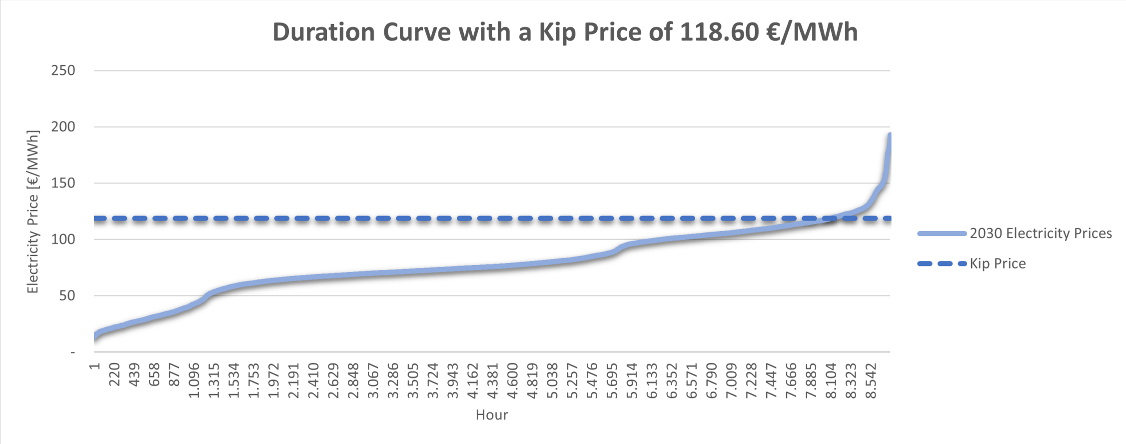

Figure 9.5. Duration curve with the estimated electricity prices in 2030 against a kip price of 118.60 €/MWh

The intermediate CO_2 storage has a capacity of 3,000 ton, and at its lowest point, it contains 1,000 ton. The e-methanol plant has a capacity of 9.75 MW e-methanol, and produces 14,300 ton/year. To do that, the e-methanol plant annually consumes 91,400 MWh hydrogen, 1,400 MWh electricity, and 8,200 MWh heat along with the 20,000 ton CO_2. A 1.02 MW electric boiler supplies the heat. Apart from the e-methanol, the plant also produces 22,300 MWh excess heat and 7,900 ton waste water annually.

The AEC electrolysis capacity is 19.24 MW. The electrolyser is annually supplied with 156,000 MWh electricity and 27,300 ton water. In return, it supplies the e-methanol plant with hydrogen and produces 41,100 MWh excess heat. Compared to e-methane production, it requires 29% less hydrogen to utilise 20,000 ton CO_2 by e-methanol production. Therefore, the electricity consumption is 25% lower in the e-methanol scenario, and almost 7 MW less electrolysis capacity is required.

9.4.2 Economic Evaluation

The initial investment is 42.1 million €, which is less than in the e-methane scenario. The explanation is partly that a smaller electrolysis capacity is sufficient, and partly that the e-methanol plant has a lower investment cost than the methanation plant due to a lower capacity. The e-methanol plant does not handle the biomethane, as the methanation plant does, which results in a lower capacity for the e-methanol plant. The annual expenses are 14.1 million €, which primarily consists of the electricity cost. The scrap value is 3.8 million €.

Figure 9.6 shows the discounted cost distribution during the evaluation period in the e-methanol scenario. The cost distribution is similar to the cost distribution in the e-methane scenario, where the cost of electricity also covers a large share of the costs (71%). The main difference is however that the cost of especially the methanol plant is lower than the methanation plant, but also the cost of the electrolyser is lower in the e-methanol scenario. The e-methanol scenario has less full load hours than the e-methane scenario, which allows the operating pattern to take advantage of lower spot prices and distribution tariffs. However, due to a lower electricity consumption, the discount on the system tariff for large-scale consumers, is not as high as in the e-methane scenario. Therefore, the average cost of electricity ends up being 75.29 €/MWh.

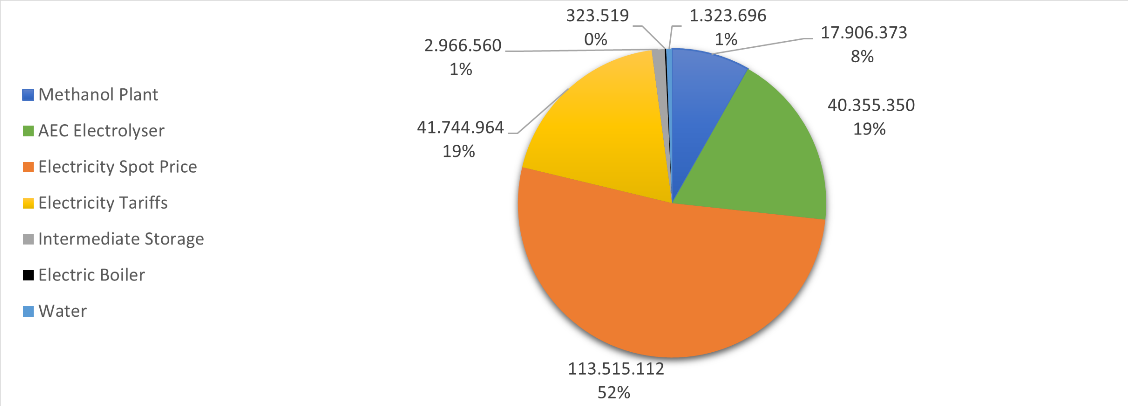

Figure 9.6. The discounted cost distribution in the e-methanol scenario [€]

The levelized cost of production is 1,203.71 €/ton e-methanol and with a selling price of 1,300 €/ton, the NPV is 17,1 million €, and the RRoR is 8% in the e-methanol scenario. The NPV is thus lower compared to the e-methane scenario. However, the costs are lower in the e-methanol scenario, which increases the RRoR and reduces the risk of the investment. Still, if the aim is to minimise the risk, the liquefaction scenario may be a better option.

Figure 9.7 shows, the sensitivity of the NPV to changes in the discount rate and the selling price. In the top, the discount rate is changed by ±3 percentage points from 5% to 2% and 8%. In the middle, the electricity cost is changed by ±25% from 75.29 €/MWh to 56.47 €/MWh and 94.11 €/MWh. In the bottom, the selling price is changed by ±25% from 1,300 €/MWh to 975 €/MWh and 1,625 €/MWh.

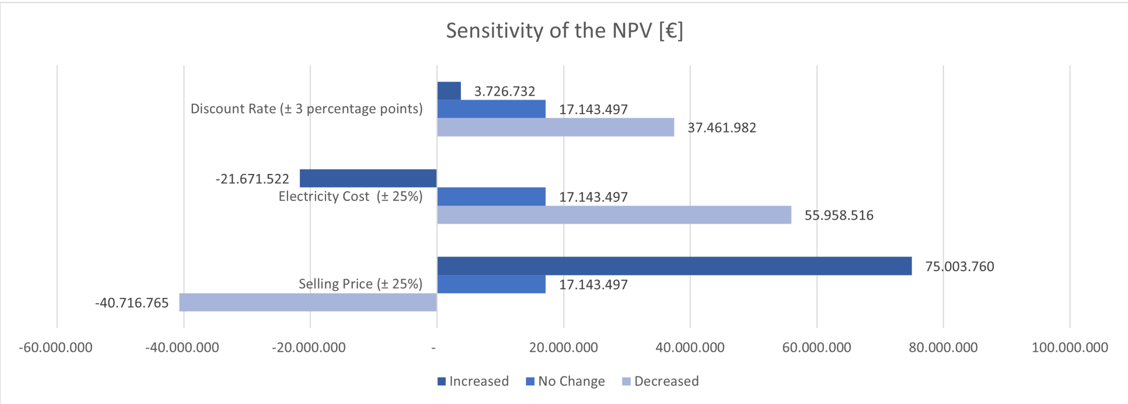

Figure 9.7. Sensitivity of the NPV in the e-methanol scenario

It appears that the NPV will become negative, if the electricity cost is increased by 25%, or the selling price is decreased by 25%. As the cost distribution is similar to the e-methane scenario, the outcome of this sensitivity study is likewise similar.

9.5 Alternative Conditions

Now that the simulation has been completed with the conditions described in Section 9.1, simulations will be conducted with alternative conditions. Simulations will be conduced with the electricity spot prices from 2040, 2030, 2023, 2022, and 2021. Likewise, the effect of changing the technologies will also be analysed.

9.5.1 Electricity Spot Prices

The electricity spot prices for 2030 will be changed to other years to see, how it affects the three scenarios. The 2030 spot prices will be changed to the spot prices of 2040, 2023, 2022, and 2021. The aim of this analysis is to test the robustness of the scenarios to changing electricity spot prices and distributions. This section features a table for each scenario that summarises the results. Details on the electricity spot prices can be found in Section 8.3.1.

Liquefaction

Table 9.1 shows that in the liquefaction scenario, operation of the plant will not change regardless of the electricity price. It is simply too expensive to increase the capacity and enable flexible operation. Therefore, the number of full load hours and the liquefaction capacity do not change despite changing electricity spot price.

The average electricity cost does however change, which affects the levelized cost of production, the NPV, and the RRoR. The average spot price is highest in 2022, which entails an average electricity cost of 222 €/MWh and the lowest NPV. Conversely, the average spot price is lowest in 2040, which entails an average electricity cost of 68 €/MWh and the highest NPV. With all the different spot prices and distributions, the NPV remains positive, which demonstrates robustness towards possible future electricity spot prices.

	2040	**2030 (Reference)**	**2023**	**2022**	**2021**
Full Load Hours	8,308	8,308	8,308	8,308	8,308
Kip Price	138 €/MWh	125 €/MWh	188 €/MWh	523 €/MWh	242 €/MWh
Average Electricity Cost	68 €/MWh	79 €/MWh	104 €/MWh	222 €/MWh	100 €/MWh
Liquefaction Capacity	2.41 ton/hour	2.41 ton/hour	2.41 ton/hour	2.41 ton/hour	2.41 ton/hour
Levelized Cost	36 €/ton	37 €/ton	41 €/ton	56 €/ton	40 €/ton
NPV	7.2 million €	6.9 million €	6.1 million €	2.1 million €	6.2 million €
RRoR	80%	74%	60%	15%	62%

Table 9.1. The effect of changing the electricity spot price distribution in the liquefaction scenario

E-methane

Table 9.2 shows that it is only with the 2030 spot prices that operation is limited by the maximum number of full load hours. With the 2040, 2023, and 2021 spot prices, operation is flexible with a capacity factor of 92-85%. The methanation and electrolysis capacities likewise increase to enable the flexibility. This suggests that it may be wise to have around 11% of surplus capacity, even though the 2030 spot prices only suggest 4% of surplus capacity.

With the 2022 spot prices, the electricity price becomes so volatile that the plant only has 3,809 full load hours. The electrolysis capacity is thus increased to 65 MW. An electrolysis capacity of 65 MW is so high that it would be more accurate to use the cost estimate for a 100 MW electrolyser than the cost estimate for a 10 MW electrolyser that has been used so far. Therefore, the cost estimate for a 100 MW electrolyser is used instead, which reduces the CAPEX by 38% per MW. The financial difference between a 10 MW and a 100 MW AEC electrolyser can be found in Appendix C.

The NPV becomes negative with the 2023, 2022, and 2021 spot prices, however it increases with the 2040 spot prices. Compared to the liquefaction scenario, the e-methane scenario is much less robust to changes in the spot prices, as the electricity cost make up a larger part of the total costs.

	2040	**2030 (Reference)**	**2023**	**2022**	**2021**
Full Load Hours	8,079	8,396	7,849	3,809	7,425
Kip Price	129 €/MWh	125 €/MWh	162 €/MWh	192 €/MWh	152 €/MWh
Average Electricity Cost	63 €/MWh	76 €/MWh	96 €/MWh	119 €/MWh	86 €/MWh
Methanation Capacity	31 MW	30 MW	32 MW	65 MW	34 MW
Electrolysis Capacity	27 MW	26 MW	28 MW	58 MW	30 MW
Levelized Cost	234 €/MWh	257 €/MWh	312 €/MWh	444 €/MWh	296 €/MWh
NPV	57.8 million €	29 million €	-39.9 million €	-206 million €	-19.9 million €
RRoR	19%	9%	-10%	-36%	-5%

Table 9.2. The effect of changing the electricity spot price distribution in the e-methane scenario

E-methanol

Table 9.3 shows that changing the spot prices has a similar effect on the e-methanol scenario, as it has on the e-methane scenario. With the 2030 spot prices there is 8% surplus capacity, however the 2040, 2023, and 2021 spot prices suggest that a surplus capacity of 21% may be more beneficial.

The 2022 spot prices entail an electrolysis capacity of 54 MW, and once again the cost estimate for a 100 MW AEC electrolyser is used instead of the cost estimate for a 10 MW AEC electrolyser.

Generally, the e-methanol scenario has a more flexible operation and less full load hours than the e-methane scenario. This means that the e-methanol scenario can benefit more from volatile spot prices, and thus the average electricity cost is lower in all five instances. Moreover, the RRoR is higher with the 2040 and the 2022 spot prices compared to the e-methane scenario.

	2040	2030 (Reference)	2023	2022	2021
Full Load Hours	7,427	8,097	6,490	2,861	6,778
Kip Price	102 €/MWh	119 €/MWh	134 €/MWh	162 €/MWh	127 €/MWh
Average Electricity Cost	59 €/MWh	75 €/MWh	87 €/MWh	100 €/MWh	82 €/MWh
Methanol Capacity	11 MW	10 MW	12 MW	28 MW	12 MW
Electrolysis Capacity	21 MW	19 MW	24 MW	54 MW	23 MW
Levelized Cost	1,059 €/ton	1,204 €/ton	1,454 €/ton	1,955 €/ton	1,369 €/ton
NPV	43 million €	17.1 million €	-27.5 million €	-117 million €	-12.2 million €
RRoR	22%	8%	-10%	-33%	-5%

Table 9.3. The effect of changing the electricity spot price distribution in the e-methanol scenario

9.5.2 Technologies

Firstly, it will be tested, how the e-methane and e-methanol scenarios respond to having the electrolyser changed from AEC to PEMEC and to SOEC. The effect of changing the methanation plant from catalytic to biological will also be analysed. Finally, the impact of technological development in all three scenarios will be investigated by changing the year of the technology data from 2020/25 to 2030. All the technical and financial specifications for the technologies are attached as Appendix C.

PEMEC

Compared to the AEC, the PEMEC has a lower efficiency and a higher CAPEX per MW. The OPEX per MW is however lower.

In both scenarios the optimal kip price decreases by 6-7 €/MWh. Due to the lower efficiency, more electricity is required for hydrogen production, which increases the incentive to utilise the lower electricity prices by flexible operation. In the e-methane scenario, the NPV decreases from 29 million € to 21 million €, and the RRoR decreases from 9% to 6%. In the e-methanol scenario, the NPV decreases from 17.1 million € to 12 million €, and the RRoR decreases from 8% to 5%.

SOEC

Compared to the AEC, the SOEC has a much higher efficiency, but the CAPEX and OPEX per MW is likewise much higher. In addition, the SOEC requires an electric boiler, as around 20% of the energy input needs to be heat.

In the e-methane scenario and the e-methanol scenario, the optimal kip price increases by respectively 54 €/MWh and 33 €/MWh. The increased kip prices is a result of partly the higher efficiency and partly the higher electrolyser cost, which makes operation with lower capacity and more full load hours beneficial. Even with the higher efficiency, the cost of the SOEC is still to high. In the e-methane scenario, the NPV decreases from 29 million € to -9.3 million €, and the RRoR decreases from 9% to -3%. In the e-methanol scenario, the NPV decreases from -10.2 million € to 12 million €, and the RRoR decreases from 8% to -4%.

Biological Methanation

Compared to catalytic methanation, biological methanation has a lower maximum number of full load hours. Therefore, the kip price needs to be reduced by 3 €/MWh. Biological methanation is less efficient, has higher CAPEX and fixed OPEX per MW, but there is no variable OPEX.

Biological methanation is simply too expensive and inefficient to be economically feasible with these framework conditions. In the e-methane scenario, the NPV decreases from 29 million € to -95 million €, and the RRoR decreases from 9% to -29%.

Technological Development

As the initial investment is happening in 2025, the technology data from 2020 and 2025 has been used. Figure 9.8 shows the NPV and the RRoR for the three scenarios, if the technology data from 2030 had been used instead. This provides insight into the expected development of the technologies during the next 5 years.

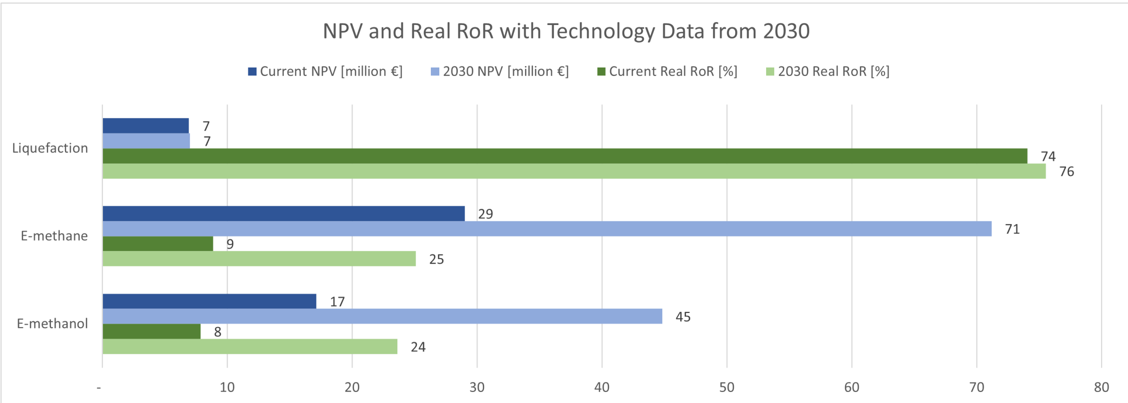

Figure 9.8. The effect of the 2030 technology data on the NPV and the RRoR in the three scenarios

On Figure 9.8, it appears that technological development will have little effect on the liquefaction scenario. By contrast, the e-methane and e-methanol scenarios are greatly impacted by the technological development. It indicates that the business case for e-methane and e-methanol will improve in the future.

By using the 2030 technology data, the levelized cost of e-methane has been reduced to 223 €/MWh, and the levelized cost of e-methanol has been reduced to 1,048 €/ton. The levelized cost of production could be further reduced by using the electricity spot prices from 2040.

9.6 Summary of Results and Key Findings

	Liquefaction	E-methane	E-methanol
Investment Cost	4.5 million €	67.5 million €	42.1 million €
Annual Expenses	394,000 €	20.9 million €	14.1 million €
Annual Production	20,000 ton	100,700 MWh	14,300 ton
Kip Price	125.47 €/MWh	124.50 €/MWh	118.60 €/MWh
Full Load Hours	8,308	8,396	8,097
Electrolysis Capacity	-	26.11 MW	19.24 MW
Plant Capacity	2.41 ton/hour	29.65 MW	9.75 MW
Annual Electricity Consumption	2,700 MWh	222,000 MWh	165,500 MWh
Average Electricity Price	78.89 €/MWh	76.00 €/MWh	75.29 €/MWh
Levelized Cost of Production	37.19 €/ton	256.89 €/MWh	1,203.71 €/ton
Selling Price	65 €/ton	280 €/MWh	1,300 €/ton
Net Present Value	6.9 million €	29 million €	17.1 million €
Real Rate of Return	74%	9%	8%

Table 9.4. Summary of the results

- The liquefaction scenario has very low costs and thus low risk. The NPV is the lowest, but the RRoR is the highest.
- The liquefaction scenario is robust against changes in the electricity cost, as it only makes up 28% of the total costs.
- Utilising CO_2 for e-methane production is around 25% more energy intensive than e-methanol production.
- The e-methane scenario has the highest costs, but the NPV is also the highest. The e-methanol scenario has lower costs, but the NPV is also lower. The e-methane scenario and the e-methanol scenario have similar RRoR.
- In the e-methane scenario and the e-methanol scenario the electricity cost make up respectively 64% and 71% of the total costs. Thus the scenarios are extremely sensitive to changes in the electricity cost.
- Regardless of the electricity spot prices, flexible operation is not economically worthwhile in the liquefaction scenario.
- Considering the electricity spot prices from 2040, 2030, 2023, and 2021, around 9% of surplus capacity is advised in the e-methane scenario, while 18% of surplus capacity is advised in the e-methanol scenario.
- Neither PEMEC, SOEC or biological methanation will improve the economic feasibility of the simulation.
- Technological development during the next 5 years will reduce the levelized cost of e-methane and e-methanol.

Discussion 10

This chapter contains the discussion of the analysis. The discussion presents an opportunity to reflect on the analysis and suggest aspects that could be subject to further research. Firstly, the results from Chapter 9 are discussed followed by a brief analysis of the impact that subsidies could have on the results. Then the third and the fourth delimitations from Section 3.2 are discussed. Finally, the application of the simulation model is discussed.

10.1 Results

In this section, the results from Chapter 9 are discussed. More specifically the certainty of the projected electricity price distributions are discussed, and it is questioned, weather a private wire to an energy park would increase the economic feasibility of the e-methane scenario and the e-methanol scenario.

10.1.1 Electricity Price Distributions

It is evident from Chapter 9 that the electricity price distributions are crucial to the economic feasibility, especially in the e-methane scenario and the e-methanol scenario. As it appears from Section 8.3.1, the projected price distributions (2040 and 2030) are more stable compared to the historical price distributions (2023, 2022, and 2021). Considering the ongoing transition from dispatchable fossil fuels to fluctuating renewable energy, it is unexpected that the future electricity prices should be less fluctuating. This could be a shortcoming of the projections.

Regardless of weather it is a shortcoming or a deliberate prediction, it has influenced the results of the simulations. It would seem more reasonable having the same low average electricity prices as projected but with more fluctuations. Such electricity price distributions would benefit the e-methane scenario and the e-methanol scenario more than the liquefaction scenario due to the regulation ability of the electrolysers. When comparing the scenarios, it is thus important to take the impact of the electricity price distributions into account.

10.1.2 Private Wire to an Energy Park

Chapter 9 shows that in the e-methane scenario and the e-methanol scenario, the cost of electricity covers respectively 64% and 71% of the total costs throughout the evaluation period. This fact makes it relevant to investigate, weather a private wire to an energy park would reduce the cost of electricity. The cost of electricity from the energy park would have to be compared to the cost of electricity from the grid. The cost of electricity from the energy park would either be determined by the CAPEX and OPEX of the energy park or by a power purchase agreement. This depends on the ownership of the energy park. In addition to the private wire, there could also be a grid connection to supply the plant during hours with no production from the energy park or low electricity prices.

Another scenario could be a centralised e-methanol plant with a private wire to a nearby energy park. This scenario would be a combination of the liquefaction scenario and the e-methanol scenario. CO_2 from multiple biogas plants would be liquefied and transported to a centralised methanol plant, where benefits from economics of scale could be achieved. The cost of CO_2 transport would have to be included, which requires intermediate CO_2 storage, as the transport would likely be by truck.

These scenarios are extensive to investigate, and therefore they are not included in the analysis. Nevertheless, they are mentioned in this discussion to highlight that they are still relevant to consider.

10.2 Impact of Subsidies

In Section 2.2, the subsidy scheme for Power-to-X and the subsidy scheme for Carbon Capture and Storage (CCS) of biogenic carbon are accounted for. In this section, the impact that these subsidies would have on the evaluation of the scenarios is discussed.

In Section 2.2, the winners of the Power-to-X tender and the winners of the CCS tender are listed along with the subsidies that they have been granted. The weighted average Power-to-X subsidy is 24 €/MWh hydrogen, and the weighed average CCS subsidy is 139 €/ton CO_2. Table 10.1 shows, what the weighted average subsidies would look like in the three scenarios. In accordance with the subsidy schemes, the Power-to-X subsidy will be paid over 10 years (2026-2035), while the CCS subsidy will be paid over 7 years (2026-2032).

	Annual Production	**Annual Subsidy**	**Total Subsidy**
Liquefaction	20,000 ton CO2	2,780,000 €	19,460,000 €
E-methane	128,670 MWh H2	3,088,075 €	30,880,755 €
E-methanol	91,429 MWh H2	2,194,285 €	21,942,857 €

Table 10.1. Potential subsidies in the three scenarios

Figure 10.1 shows, how the subsidies would affect the Net Present Value (NPV) and Real Rate of Return (RRoR) in the three scenarios. The subsidies would have the greatest impact on the liquefaction scenario and more or less the same impact on the e-methane scenario and the e-methanol scenario. The main takeaway here is that a subsidy could make the difference between an unprofitable project and a profitable project. It is therefore always worthwhile to examine, weather a project can qualify for a subsidy.

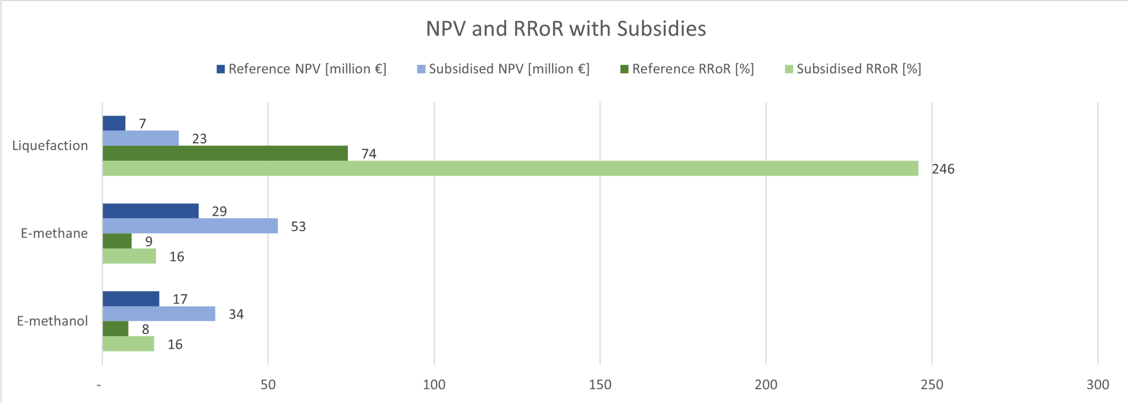

Figure 10.1. The impact of a 24 €/MWh hydrogen subsidy and a 139 €/ton CCS subsidy

This subsidy analysis is, however, made with reservations. To qualify for a subsidy, there is always requirements that have to be fulfilled, and it has not been further examined, weather the scenarios live up to the requirements. Beyond that, the CCS subsidy is only granted for CO_2 stored underground, which means that the cost of transport and storage facilities have to be included in the evaluation. Similarly, the Power-to-X subsidy is meant to benefit the whole value chain, and not just the hydrogen producer.

10.3 Delimitations

In Section 3.2, the delimitations of the analysis are outlined. Two of these delimitations are that all of the CO_2 from the biogas plant has to be utilised and that there is no hydrogen storage included in the simulation model. The impact of these two delimitations is discussed in this section.

10.3.1 No intermediate CO2 or Biogas Storage

As all of the CO_2 has to be utilised an intermediate CO_2 storage is required in the liquefaction scenario and the e-methanol scenario, while an intermediate biogas storage is required in the e-methane scenario. However, if not all of the CO_2 had to be utilised, these intermediate storages could be removed. This would imply that CO_2 is utilised, when the plant is in operation, and when the plant is not in operation, the CO_2 is emitted to the atmosphere. In this section, it is investigated, how the scenarios respond to having the intermediate storages removed. On one hand, the levelized cost of production will be reduced by removing the cost of intermediate storage, but on the other hand, CO_2 will be wasted and therefore generate no income.

To do the simulations without an intermediate storage, the simulation model had to be rethought. Before, the electricity consumption had been determined by the amount of available CO_2, while the capacity had been determined by the kip price. Now, without an intermediate storage, the capacity is fixed to match the CO_2-outflow from the biogas plant, and the electricity consumption is determined by the number of full load hours. Therefore, the highest NPV is found by optimising the number of full load hours instead of the kip price. The results of the simulations are shown on Table 10.2.

	Liquefaction	**E-methane**	**E-methanol**
Investment Cost	3 million €	62.3 million €	37.3 million €
Annual Expenses	315,000 €	19.9 million €	12.5 million €
Annual Production	19,000 ton	96,400 MWh	12,900 ton
Full Load Hours	8,308	8,385	7,880
Electrolysis Capacity	-	25.02 MW	17.78 MW
Plant Capacity	2.28 ton/hour	28.42 MW	9.01 MW
Annual Electricity Consumption	2,500 MWh	212,500 MWh	148,800 MWh
Average Electricity Price	78.89 €/MWh	76.06 €/MWh	74.57 €/MWh
Levelized Cost of Production	27.93 €/ton	254.05 €/MWh	1,187.88 €/ton
Selling Price	65 €/ton	280 €/MWh	1,300 €/ton
Net Present Value	8.4 million €	31.2 million €	18 million €
Real Rate of Return	121%	10%	9%

Table 10.2. Results without intermediate storages

Table 10.2 shows that both costs and production decreases without an intermediate storage. In all three scenarios, the levelized cost of production decreases, while the NPV and Real Rate of Return increases, which means that the cost of having an intermediate storage is higher than the additional income from utilising all of the CO_2. According to this study, it is therefore not beneficial to have an intermediate storage of CO_2 or biogas.

Using the 2023 electricity price distribution instead of the 2030 distribution, the same conclusion is reached, when simulations are made with and without intermediate storage. As the electricity price in 2023 is more volatile than in 2030, the annual production decreases to merely 66,900 MWh e-methane and 6,800 ton e-methanol. It is simply not profitable to have more full load hours and thus utilise more of the CO_2 due to the high electricity prices. So, intermediate storage is likewise not a wise investment with the 2023 distribution.

10.3.2 Hydrogen Storage

Due to the complexity of developing a simulation model with multiple production patterns, the analysis has been delimited from including an intermediate hydrogen storage in the e-methane scenario and e-methanol scenario. A hydrogen storage would allow the electrolysers to regulate production according to the electricity price, while the methanation plant and the methanol plant would have a more stable production pattern. The methanation plant and the methanol plant would thus have lower capacities and more full load hours.

The immediate purpose of adding a hydrogen storage would not be to improve the business case by reducing the cost of the methanation plant and the methanol plant. A hydrogen storage is also costly, so it is uncertain, weather it would better or worsen the economic feasibility. The purpose would rather be to make the simulation model more realistic by taking the regulation ability of the technologies into consideration. As mentioned in Section 6.4, the electrolysers can all regulate production within a few minutes, when they are on standby, and the same applies to the electric boiler. However, even on standby, it can take more than an hour for the methanation plant and the methanol plant to regulate production [DEA, 2024e]. Therefore, a hydrogen storage would make the simulation model more realistic, but it is uncertain, how it would affect the economic feasibility.

10.4 Application of the Simulation Model

In Chapter 8, a simulation model is developed in Excel with the aim of evaluating the business case of utilising CO_2 from Danish biogas plants. In this section, the application of the simulation model is discussed by commenting on the purpose and strengths of the model, and potential improvements to advance the model.

The purpose of the model is to ease the process of making techno-economic pre-feasibility studies. The aim of a pre-feasibility study is to assess the immediate feasibility to determine, weather there are grounds for further investigation. A pre-feasibility is done prior to a more elaborate feasibility study, which is more exhaustive and resource-intensive. The simulation results are therefore not sufficient to create a basis for a final investment decision, but they can provide preliminary insights. The model is primarily meant for owners of biogas plants, who want an assessment of their business case. The model can likewise be used by other operators in the value chain or policymakers.

The strengths of the model are the simplicity and the adaptability. The simplicity makes the model quick and easy to use. Early in the process, the model can narrow down the scope of the feasibility study, so that every scenario does not have to be thoroughly examined. Company resources can thus be focused on the most promising scenarios. The model can be adapted to examine scenarios with various conditions and requirements. In that way, an overview of different investment options can be obtained with few resources spend.

Even though, the model is only supposed to be used for initial screenings, there is still room for improvements. The technical and financial data that is attached as Appendix C, is generic and indicates the general specifications for the technologies on the market. Specific data could be collected from suppliers to make the simulations more accurate to a specific case. When evaluating a specific case, the cost of transport from producer to consumer could be taken into account, and it could be investigated, weather the excess heat could be used for district heating or other purposes at the biogas plant. As mentioned in Section 3.2, the model could benefit from including an intermediate hydrogen storage and considering the regulation ability of the units to a greater extent.

Conclusion 11

Biogas upgrading presents a very cost-effective way of acquiring biogenic CO_2 that by means of Power-to-X and Carbon Capture and Storage can contribute to fulfilling the climate goals from the Danish climate law. This thesis has examined the business case of utilising the CO_2 by simulating three scenarios in an Excel model. In all of the scenarios, 20,000 tons CO_2 is available annually, and it must all be utilised. The CO_2 can be (1) sold as liquid CO_2, (2) utilised for on-site production of e-methane, or (3) utilised for on-site production of e-methanol. From analysing the market conditions for the products, it has been found that the markets for liquid CO_2, e-methane, and e-methanol are growing. Reasonable selling prices have been determined to be 65 €/ton liquid CO_2, 280 €/MWh e-methane, and 1,300 €/ton e-methanol.

The three scenarios have been simulated against the projected electricity price distribution of 2030. The results of the simulations are shown on Table 11.1.

	Liquefaction	**E-methane**	**E-methanol**
Investment Cost	4.5 million €	67.5 million €	42.1 million €
Annual Expenses	394,000 €	20.9 million €	14.1 million €
Annual Production	20,000 ton	100,700 MWh	14,300 ton
Full Load Hours	8,308	8,396	8,097
Levelized Cost of Production	37.19 €/ton	256.89 €/MWh	1,203.71 €/ton
Net Present Value	6.9 million €	29 million €	17.1 million €
Real Rate of Return	74%	9%	8%

Table 11.1. Simulation results in the three scenarios

As it appears from Table 11.1, the liquefaction scenario is the safest investment due to the low costs and the high real rate of return. The e-methane scenario and the e-methanol scenario are associated with more risk, but they do have higher net present values. The majority of the total costs are made up of electricity costs in the e-methane scenario (64%) and the e-methanol scenario (71%). This makes the scenarios more sensitive to changes in the electricity price compared to the liquefaction scenario (28%). When changing the electricity price distribution, it affects the optimal number of full load hours in the e-methane scenario and the e-methanol scenario. The liquefaction plant should by contrast be kept in operation as mush as possible regardless of the electricity price distribution. It is likely that the future electricity price will be more fluctuating than the 2030 electricity price distribution. More volatility will to a greater extent benefit the flexible production in the e-methane scenario and the e-methanol scenario. It is also expected that technological development during the next five years will greatly improve the the e-methane scenario and the e-methanol scenario, while the liquefaction scenario will remain close to unchanged.

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Interview with Frank Rosager A

Frank Rosager, who is the CEO of Biogas Danmark, was interviewed on Tuesday the 12th of March 2024 via Microsoft Teams. The interview was conducted in Danish, so this transcription is a rough translation of the original statements. It should also be mentioned that this is not a transcription of the whole interview.

What do you think of the new subsidy scheme that will subsidise both biomethane and e-methane?

"Due to some uncertainty in the EU, it has been decided that you can not get both the new subsidy and biogas certificates for the methane at the same time. That has made the subsidy scheme less attractive. If you can not get biogas certificates, you can not sell the gas as biomethane. The biomethane will therefore be treated as natural gas, and that is a big problem. With the current gas prices, the new subsidy will not be able to cover the cost of production without biogas certificates. So, I believe that new biogas plants will focus on unsubsidised biogas certificates, because they are worth more than the subsidy."

How come that there is a price difference between subsidised biogas certificates and unsubsidised biogas certificates?

"If you have a requirement for CO_2 displacement, as transport sectors in various countries have, then you are not allowed to use subsidised biofuels. According to EU legislation, subsidies must only be used to realise initiatives that will not otherwise be realised, and as the CO_2 displacement is a requirement, it will be realised with or without a subsidy."

Will the new subsidy scheme be used, if unsubsidised biogas certificates are worth more than the subsidy?

"Well, the subsidy is guaranteed for 20 years, while unsubsidised biogas certificates relies on the market. (...) You can also on a monthly basis decide, weather you want the subsidy or not. So, if the market for unsubsidised biogas certificates collapses, then you can get the subsidy instead. It is likewise an option in the current subsidy scheme."

I can see that it will be quite challenging to determine the income from selling e-methane, as it depends on various prerequisites. Do you have any advise for that?

"I am of the impression that e-methane is in relatively high demand on the German transport market. (...) A German company called Agriportance has some figures that show the price development of biogas certificates. As you can see from the figures, the price

is decreasing, because the Chinese have disrupted the market. They did that 6-7 years ago as well with used frying oil. That disrupted the market, until the EU put a maximum limit of 1.7% on admixing used frying oil in diesel. Now the Chinese are disrupting the market with rotten palm oil. So, that is why, the price is decreasing. I am, however, expecting that the EU also puts a stop to the disruption this time. (...) It is my understanding that the biogas certificates for e-methane are worth the same as biogas certificates for biomethane from manure."

So the methane and the biogas certificates are two different commodities?

"Yes, you are trading the methane and the biogas certificates separately. The price of the methane corresponds to the gas price, which you can find on our website."

Interview with Anders Søgaard Kristensen B

Anders Søgaard Kristensen, who is a manager at Rambøll Management Consulting, was interviewed on Monday the 18th of March 2024. The interview was conducted in Danish, so this transcription is a translation of the original statements. It should also be mentioned that this is not a transcription of the whole interview.

I have found some news articles from September last year that reported e-methanol prices of 2,500 \$/ton and 2,429.8 \$/ton. What do you think of those prices for the purpose of determining a selling price for my analysis?

"I think that it is probably the most accurate academic approach to determining a realistic selling price. Using price points from the market is a good way to validate your assumptions. It is also Maersk that I would take into consideration, as they are the first ones to commit to a certain amount of e-methanol. When the price points furthermore are so similar, then it becomes easier to determine a credible selling price."

It seems like the cost of production and the selling price for fossil methanol from natural gas are similar in Europe. Would it then be a valid approach to estimate a future selling price for e-methanol based on the expected production costs for e-methanol in the future?

"Yes, I also believe that it would be a reasonable approach. It is also a relatively transparent approach, which subsequently could be subject to a sensitivity study."

In terms of selling CO_2 directly, Agriportance has estimated the market price for liquid CO_2 in Germany. As you can see on the figures, the market price fluctuates around 40 €/ton. How does that compare with your estimates?

"On a project, I have previously seen a CO_2 price that fluctuated between 55-85 €/ton. However, this adds to the point that the market is not fully established yet, so the CO_2 price is difficult to definitively determine."

Can I ask, when you encountered those CO_2 prices?

"It was last winter, so it was also in the end of a period with relatively high energy prices and so forth. It was part of a contract, where the price was reevaluated annually."

If we return to e-methanol, do you see onsite production of e-methanol at biogas plants as a realistic scenario? The size of the biogas plant limits the achievable benefits from economics of scale, however, CO_2 is more expensive

to transport compared to e-methanol.

"My first note is that I recognise the limitations in terms of benefits from economics of scale. This is not to say that it is not something that can be aimed at over time. Something that for example Nature Energy could do, even though it is expensive to transport CO_2, is to make some kind of cluster at one of the biogas plants, where the CO_2 is collected to improve the business case. What, I will also point out, is that there is more certainty of sale, when producing biomethane. That is not the case with e-methanol, where there is uncertainty about the buyers, and the current and future selling prices. In addition, the production pattern of e-methanol is also more intermittent than biomethane. So there are some challenges, but I will not reject the scenario entirely."

Do you have any comments on my estimation of a selling price for e-methane?

"The gas price is relatively transparent, however, the price has also been quite volatile during the last couple of years. Since then, there has been a regression to the mean. I can not say with certainty, what the future gas price will be, but I think that the current gas price is around 30 €/MWh, and the gas price will be around 25-30 €/MWh. In addition, there will also be income from selling biogas certificates."

Technical and Financial Specifications C

Liquefaction Plant	2025	2030
Typical Capacity [ton CO2 / hour]	2	2
Electricity Consumption [MWh / ton CO2]	0,133	0,129
Excess Heat [MWh / ton CO2]	0,343	0,341
Water Output [kg / ton CO2]	17,4	17,4
Technical Lifetime [years]	20	20
Maximum Full Load Hours	8.308	8.308
CAPEX [€ / (ton CO2 / hour)]	1.330.000	1.330.000
Fixed OPEX [€ / (ton CO2 / hour) / year]	50.000	50.000

Figure C.1. The specifications for the liquefaction plant [DEA, 2023c]

Methanation Plant					
Catalytic Methanation			Biological Methanation		
	2020	2030		2025	2030
Typical Capacity [MW Methane]	3,3	8,3	Typical Capacity [MW Methane]	8,0	15,9
Biogas Consumption [MWh / Total Input]	0,53	0,53	Biogas Consumption [MWh / Total Input]	0,55	0,55
H2 Consumption [MWh / Total Input]	0,46	0,46	H2 Consumption [MWh / Total Input]	0,43	0,43
Electricity Consumption [MWh / Total Input]	0,01	0,01	Electricity Consumption [MWh / Total Input]	0,02	0,02
Methane Production [MWh / MWh Total Input]	0,89	0,89	Methane Production [MWh / MWh Total Input]	0,79	0,79
Excess Heat [MWh / MWh Total Input]	0,10	0,10	Excess Heat [MWh / MWh Total Input]	0,16	0,16
Maximum Full Load Hours	8.396	8.746	Maximum Full Load Hours	8.322	8.497
Technical Lifetime [years]	25	25	Technical Lifetime [years]	25	30
CAPEX [€ / MW]	960.000	800.000	CAPEX [€ / MW]	2.100.000	1.500.000
Fixed OPEX [€ / MW / year]	39.000	32.000	Fixed OPEX [€ / MW / year]	80.000	80.000
Variable OPEX [€ / MWh Methane]	4,59	3,83	Variable OPEX [€ / MWh Methane]	-	-

Figure C.2. The specifications for catalytic and biological methanation plants [DEA, 2024d] [DEA, 2024i]

E-methanol Plant	2025	2030
Typical Capacity [MW Methanol]	69	138
CO2 Consumption [ton / ton e-methanol]	1,40	1,40
H2 Consumption [MWh / ton e-methanol]	6,40	6,40
Electricity Consumption [MWh / ton e-methanol]	0,10	0,10
Heat Consumption [MWh / ton e-methanol]	0,58	0,58
e-methanol Production [MWh / Total Input]	0,78	0,78
Excess Heat [MWh / Total Input]	0,22	0,22
Water Output [ton / ton e-methanol]	0,55	0,55
Technical Lifetime [years]	30	30
Maximum Full Load Hours	8.389	8.476
CAPEX [€ / MW]	1.350.000	1.090.000
Fixed OPEX [€ / MW / year]	39.000	30.000

Figure C.3. The specifications for the methanol plant [DEA, 2024d]

Electrolyser					
AEC 10 MW	2025	2030	**AEC 100 MW**	2025	2030
Efficiency	58,7%	62,2%	Efficiency	58,7%	62,2%
Water Consumption [ton / MWh Input]	0,175	0,185	Water Consumption [ton / MWh Input]	0,175	0,185
Excess Heat [MWh / MWh Input]	0,264	0,223	Excess Heat [MWh / MWh Input]	0,264	0,223
Maximum Full Load Hours	8.486	8.486	Maximum Full Load Hours	8.486	8.486
Technical Lifetime [years]	25	25	Technical Lifetime [years]	25	25
CAPEX [€ / MW]	1.400.000	875.000	CAPEX [€ / MW]	875.000	550.000
Fixed OPEX [% of CAPEX / year]	0,04	0,04	Fixed OPEX [% of CAPEX / year]	0,04	0,04
PEMEC 10 MW	2025	2030	**PEMEC 100 MW**	2025	2030
Efficiency	55,0%	58,5%	Efficiency	55,0%	58,5%
Water Consumption [ton / MWh Input]	0,167	0,178	Water Consumption [ton / MWh Input]	0,167	0,178
Excess Heat [MWh / MWh Input]	0,307	0,265	Excess Heat [MWh / MWh Input]	0,307	0,265
Maximum Full Load Hours	8.486	8.486	Maximum Full Load Hours	8.486	8.486
Technical Lifetime [years]	25	25	Technical Lifetime [years]	25	25
CAPEX [€ / MW]	1.425.000	950.000	CAPEX [€ / MW]	975.000	650.000
Fixed OPEX [% of CAPEX / year]	0,02	0,02	Fixed OPEX [% of CAPEX / year]	0,02	0,02
SOEC 10 MW	2025	2030	**SOEC 100 MW**	2025	2030
Efficiency	67,4%	69,6%	Efficiency	67,4%	69,6%
Electricity Share of Input	79,5%	80,5%	Electricity Share of Input	79,5%	80,5%
Heat Share of Input	20,5%	19,5%	Heat Share of Input	20,5%	19,5%
Water Consumption [ton / MWh Input]	0,228	0,237	Water Consumption [ton / MWh Input]	0,228	0,237
Excess Heat [MWh / MWh Input]	-	-	Excess Heat [MWh / MWh Input]	-	-
Maximum Full Load Hours	8.486	8.486	Maximum Full Load Hours	8.486	8.486
Technical Lifetime [years]	25	25	Technical Lifetime [years]	25	25
CAPEX [€ / MW]	2.075.000	1.250.000	CAPEX [€ / MW]	1.300.000	775.000
Fixed OPEX [% of CAPEX / year]	0,12	0,12	Fixed OPEX [% of CAPEX / year]	0,12	0,12

Figure C.4. The specifications for AEC, PEMEC and SOEC electrolysers with capacities of 10 MW and 100 MW [DEA, 2024d]

Storage			
CO2			
	Low Pressure	Medium Pressure	High Pressure
CAPEX [€ / ton CO2]	603,72	930,15	3.595,41
Fixed OPEX [€ / ton CO2 / year]	30,19	46,51	179,77
Technical Lifetime [years]	25	25	25
Biogas			
	Low Pressure	Medium Pressure	High Pressure
CAPEX [€ / Nm3 Biogas]	1,19	1,84	7,11
Fixed OPEX [€ / Nm3 biogas / year]	0,06	0,09	0,36
Technical Lifetime [years]	25	25	25

Figure C.5. The specifications for the CO_2 storage and the biogas storage with low pressure (5.5-9.8 bar), medium pressure (14-20 bar), and high pressure (45-72 bar) [Durusut og Joos, 2018] [DEA, 2023c]

Electric Boiler					
2 MW			15 MW		
	2020	2030		2020	2030
Maximum Full Load Hours	8.671	8.671	Maximum Full Load Hours	8.671	8.671
Technical Lifetime [years]	25	25	Technical Lifetime [years]	25	25
CAPEX [€ / MW]	210.000	190.000	CAPEX [€ / MW]	100.000	80.000
Fixed OPEX [€ / MW / year]	1.231	1.173	Fixed OPEX [€ / MW / year]	1.107	1.056
Variable OPEX [€ / MWh]	1	1	Variable OPEX [€ / MWh]	1	1

Figure C.6. The specifications for the electric boiler with a capacity of 2 MW and 15 MW [DEA, 2022]